November 5, 2002

ENCANA™

third quarter report 3

EnCana cash flow tops $1 billion in third quarter

Sales increase 9% to 718,000 boe/d, natural gas and oil sales on track, gas production growth positions EnCana to capitalize on anticipated strong prices

Calgary, Alberta (November 5, 2002) – EnCana Corporation (TSX & NYSE: ECA) generated $1,022 million of cash flow, or $2.12 per share diluted, in the third quarter of 2002. Daily oil and gas sales reached 718,225 barrels of oil equivalent, up nine percent from the pro forma third quarter results of EnCana's founding companies one year earlier. The Company's average daily sales are on track to achieve publicly stated targets for 2002.

All references to 2001 production and nine month 2002 financial information in this quarterly report text and tables for EnCana are presented on a pro forma basis as if the merger of PanCanadian Energy Corporation ("PanCanadian" or "PCE") and Alberta Energy Company Ltd. ("AEC") had occurred at the beginning of the respective periods.

ENCANA CASH FLOW AND EARNINGS

	Q3		Nine Month Pro Forma	
	$MM	$/share	$MM	$/share
Cash flow	1,022	2.12	2,739	5.66
Earnings excluding foreign exchange on translation of US$ debt (after tax)	349	0.72	808	1.66
Foreign exchange gain or (loss) on translation of US$ debt (after tax)	(145)	(0.30)	17	0.04
Net earnings as reported	204	0.42	825	1.70

ENCANA ACHIEVES STRONG THIRD QUARTER EARNINGS FROM OPERATIONS

In the third quarter of 2002, EnCana earned $349 million, or $0.72 per share diluted, excluding an unrealized after tax foreign exchange loss of $145 million, or $0.30 per share diluted, on EnCana's US dollar denominated debt. This loss, which had no impact on cash flow, resulted from the Canadian dollar depreciating relative to the US dollar during the quarter. Including the impact of the foreign exchange loss, the company earned $204 million, or $0.42 per share diluted, in the quarter. The year to date impact of foreign exchange on US dollar denominated debt is an unrealized after tax net gain of $17 million, or $0.04 per share diluted, resulting in nine month pro forma net earnings of $825 million, or $1.70 per common share diluted.

"Our third quarter results confirm that we are right on track to accomplish our 2002 sales growth targets and are well positioned to achieve our industry leading 2003 sales growth targets. EnCana has once again produced profitable growth from its high quality asset base, a solid inventory of identifiable growth opportunities, strong technical expertise and cost control. Our increased production base of more than 718,000 barrels of oil equivalent per day, combined with higher than expected oil prices, yielded solid results. As winter approaches, EnCana is poised to capitalize on anticipated strong seasonal gas markets by increasing sales from our growing production and by withdrawing produced gas stored earlier this year," said Gwyn Morgan, EnCana's President & Chief Executive Officer.

"In the seven months since creating EnCana, our teams have come together in an efficient integration as we build a best-in-class independent. We have not missed a beat in delivering profit and growth for shareholders while enhancing our already strong suite of assets. During the third quarter, we completed our second opportunistic natural gas acquisition this year, adding 600 billion cubic feet equivalent of established reserves in the U.S. Rockies – currently our highest production growth region. Our exploration teams are also appraising promising oil and natural gas discoveries in the Gulf of Mexico and offshore Canada's East Coast. Plus we have an exciting roster of drilling prospects lined up for evaluation this winter," Morgan said. "We also continued to optimize our portfolio, making good progress towards the planned sale of our interests in two major oil pipelines. This anticipated disposition is expected to be completed by year end."

STRONG OIL AND NATURAL GAS GROWTH CONTINUES IN THIRD QUARTER

EnCana's third quarter natural gas production averaged 2.8 billion cubic feet per day, up 10 percent over pro forma results in the third quarter of 2001. During the quarter, 80 million cubic feet per day was injected into storage, yielding third quarter sales of 2.7 billion cubic feet per day. Oil and natural gas liquids sales averaged 270,225 barrels per day, up about six percent, compared to pro forma results in the third quarter of 2001. Conventional operating plus administrative costs were approximately $4.91 per barrel of oil equivalent in the quarter. EnCana drilled 571 net wells in the third quarter.

For the three months ended September 30, 2002, EnCana's highlights include:

- Earnings, excluding impact of foreign exchange on translation of US dollar debt (after tax), of $349 million, or $0.72 per common share diluted
- Reported net earnings of $204 million, or $0.42 per common share diluted
- Cash flow of $1,022 million, or $2.12 per common share diluted
- Natural gas sales of 2,688 million cubic feet per day, up 10 percent from pro forma third quarter of 2001, with the average realized price declining 15 percent to $3.56 per thousand cubic feet
- Crude oil and natural gas liquids sales of 270,225 barrels per day, up six percent from pro forma third quarter of 2001, with the average realized price up nine percent to $33.64 per barrel
- Total capital investment, including acquisitions and dispositions, of $1,374 million
- A strong financial position with debt to capitalization of 39 percent (all preferred securities included as debt)

NATURAL GAS PRICES BEGIN STRENGTHENING IN ADVANCE OF WINTER

The average industry gas price at AECO for the third quarter of 2002 was $3.25 per thousand cubic feet, compared to $3.92 per thousand cubic feet in the same period a year earlier. However, EnCana's average realized gas price in the third quarter was $3.56 per thousand cubic feet, reflecting the positive impact of having about 1.4 billion cubic feet of gas per day hedged. EnCana's fixed price hedges for the third quarter included 875 million cubic feet per day at an effective AECO price of C$4.24 per thousand cubic feet, 333 million cubic feet per day at an effective Opal, Wyo. price of US$2.61 per thousand cubic feet and 205 million cubic feet per day at a NYMEX related price of US$3.33 per thousand cubic feet. Gas prices have reversed their downward trend and shown significant strength over the past month, achieving levels higher than at the same time in 2001.

ENCANA STORAGE POISED TO INCREASE WINTER GAS SALES

EnCana has approximately 26 billion cubic feet of produced gas in its North American storage facilities and is poised to increase sales to capitalize on seasonally stronger pricing. Using a combination of storage and field production, EnCana's fourth quarter sales are expected to exceed three billion cubic feet per day.

WORLD OIL PRICES STRONGER, CANADIAN HEAVY OIL DIFFERENTIALS NARROWED FURTHER

In the third quarter of 2002, the average West Texas Intermediate crude oil benchmark price was US$28.25 per barrel, up six percent from US$26.60 per barrel for the same quarter in 2001. World oil prices strengthened during the third quarter primarily due to increasing speculation over U.S. military action against Iraq. In addition to this global oil price rise, Canadian heavy oil differentials narrowed in the third quarter, averaging US$5.38 compared with US$7.16 per barrel in the third quarter of 2001, due to lower world-wide heavy crude oil production in 2002. In Ecuador, the third quarter oil quality differential also improved, dropping to average US$4.35 from US$5.22 per barrel in the third quarter of 2001, due to lower OPEC production of heavy oil. Entering the fourth quarter, Canadian heavy oil differentials are widening, due to softer winter demand for heavier grades of oil.

CRUDE OIL PRICE RISK HEDGING PROGRAM

EnCana has entered into a crude oil price risk management program for a portion of its oil production in 2003 and 2004. For 2003, EnCana has established a series of fixed price swaps on 40,000 barrels per day at an average WTI price of US$25.72 per barrel. Another 40,000 barrels per day has been hedged using costless collars with a WTI floor averaging US$21.95 per barrel and a cap of US$29.00 per barrel. For 2004, EnCana has entered into a series of swaps on 50,000 barrels per day at an average price of US$23.10 per barrel and costless collars for an additional 62,500 barrels per day with a WTI floor of US$20.00 per barrel and a cap averaging US$25.69 per barrel.

NINE MONTH PRO FORMA FINANCIAL AND OPERATING PERFORMANCE

For the first nine months of 2002, EnCana earned pro forma $825 million, or $1.70 per share diluted, and generated $2.7 billion in cash flow, or $5.66 per share diluted. Sales for the first nine months averaged 704,000 barrels of oil equivalent per day, up 10 percent over pro forma sales from one year earlier. Daily sales for the first nine months were comprised of 2.7 billion cubic feet of natural gas, up 14 percent in the past year, and 260,136 barrels of oil and natural gas liquids, up four percent over pro forma sales for the first nine months of 2001. EnCana drilled 2,114 net wells in the first nine months.

SALES TARGETS ON TRACK FOR 2002, GROWTH EXPECTED TO CONTINUE IN 2003

EnCana's 2002 daily sales volumes are forecast to grow by about 10 percent from 2001 pro forma sales. The 2002 forecast is between 2,715 million and 2,785 million cubic feet of gas and 245,000 and 264,000 barrels of oil, for a total daily sales forecast of between 697,000 and 728,000 barrels of oil equivalent. Sales volumes during 2003 are expected to increase to between 788,000 and 830,000 barrels of oil equivalent per day.

Important Notice: Readers are cautioned that a portion of the nine month results and the comparisons to prior years' results are based on pro forma calculations and these pro forma results may not reflect all adjustments and reconciliations that may be required under Canadian generally accepted accounting principles. These pro forma results may not be indicative of the results that actually would have occurred or of the results that may be obtained in the future.

Financial Highlights

As at and for the Period Ending September 30, 2002 *($ millions, except per share amounts)*	**EnCana Three Months Actuals**	EnCana Nine Months Pro Forma
Revenues, net of royalties and production taxes	**2,882**	7,821
Cash flow	**1,022**	2,739
Per share – basic	**2.14**	5.78
Per share – diluted	**2.12**	5.66
Net earnings	**204**	825
Per share – basic*	**0.43**	1.74
Per share – diluted	**0.42**	1.70
Capital investment, excluding dispositions	**1,507**	4,249
Total assets	**30,788**	n/a
Long-term debt	**8,306**	n/a
Preferred securities	**584**	n/a
Shareholders' equity	**13,342**	n/a
Debt-to-capitalization ratio (adjusted for working capital and including preferred securities as debt)	**39%**	n/a
Common Shares		
Outstanding September 30, 2002 *(millions)*	**477.4**	n/a
Weighted average diluted *(millions)*	**482.2**	483.6

* Impact of including share options in earnings calculations
As required by Canadian generally accepted accounting principles, the notes to EnCana's third quarter financial statements show that the inclusion of stock options as compensation expense in the calculations of earnings would have resulted in a reduction of 14 cents in basic earnings per share in the first nine months of 2002.

Operating Highlights

For the Three Months Ending September 30	**Q3 2002 Actuals**	Q3 2001 Pro Forma	Percent Change
Sales			
Total barrels of oil equivalent per day	**718,225**	661,202	+9
Natural gas *(million cubic feet per day)*	**2,688**	2,444	+10
Total liquids *(barrels per day)*	**270,225**	253,869	+6
Onshore North America			
Conventional oil and NGLs	**169,069**	160,790	+5
Syncrude	**36,039**	28,938	+25
Offshore and International	**65,117**	64,141	+2
Prices			
North American gas price *($ per thousand cubic feet)*	**3.56**	4.19	-15
North American conventional oil price *($ per barrel)*			
Light/medium	**35.12**	33.51	+5
Heavy	**28.55**	24.94	+14
Syncrude *($ per barrel)*	**42.54**	40.74	+4
International crude oil *($ per barrel)*			
Ecuador	**33.59**	28.43	+18
U.K.	**39.30**	32.05	+23
Natural gas liquids *($ per barrel)*	**31.18**	31.21	–
Total liquids *($ per barrel)*	**33.64**	30.82	+9

ENCANA CORPORATE DEVELOPMENTS

Strategic realignment continues

EnCana continues to sharpen its focus on core operated exploration and production assets, which are characterized by high working interests in large resource properties with low operating costs, strategic advantage and the potential to achieve strong growth yielding attractive rates of return. This year, the Company has completed two significant upstream acquisitions in the U.S. Rockies adding 1.1 trillion cubic feet of high-quality, established natural gas reserves. EnCana has also sold some smaller, non-core upstream and midstream production assets, bringing total proceeds from dispositions, as of early November 2002, to approximately $525 million before tax. Discussions are continuing with a variety of parties who have expressed strong interest in purchasing EnCana's Express and Cold Lake pipeline assets, a transaction which the company expects to complete by year-end. EnCana plans to continue this strategic refinement of its asset portfolio.

Merger integration on track after creation of EnCana Corporation on April 5, 2002

The creation of EnCana and integration of its two founding companies, Alberta Energy Company Ltd. and PanCanadian Energy Corporation, is on track. "Daily discussions, from the senior executive team to the field production meetings, have shifted away from integration issues to focus on achieving best-in-class performance," Morgan said. The company is targeting annual, post-merger synergies, on a pre-tax basis in 2003, of approximately $250 million in operations and administration and approximately $250 million in capital investments.

Dividends

The board of directors of EnCana declared a quarterly dividend of ten cents (10 cents) per share payable on December 31, 2002 to common shareholders of record as of December 13, 2002.

Normal Course Issuer Bid approved

Effective October 16, 2002, EnCana received approval from the Toronto Stock Exchange for a Normal Course Issuer Bid. Under the bid, EnCana may purchase for cancellation up to 23,843,565 of its Common Shares, representing five percent of the 476,871,300 Common Shares outstanding as at October 4, 2002. On October 22, 2002, the company became entitled to make purchases under the bid for a period of up to one year.

AEC capital securities meeting set

AEC has set November 26, 2002 as the date for a meeting of holders of its 8.38 percent Capital Securities due June 27, 2040 and its 8.50 percent Capital Securities due December 20, 2040 to consider, and if thought advisable to approve, amendments to the terms of such Capital Securities to provide AEC with the right to call for the early redemption of the Capital Securities.

ENCANA OPERATIONAL HIGHLIGHTS

Onshore North America

Continued strong natural gas growth EnCana's North American natural gas production continued to grow during the third quarter, reaching nearly 2.8 billion cubic feet per day, up 10 percent compared to pro forma results of the same period in 2001. Daily production growth was led by increases in the U.S. Rockies and northeast British Columbia. The Onshore North America division drilled 559 net wells during the third quarter.

Exceptional growth in the U.S. Rockies EnCana completed its second U.S. Rockies acquisition since the company's creation in April with the purchase of an additional 25 percent interest in the Jonah gas field for approximately C$539 million. With this addition of approximately 600 billion cubic feet equivalent of established natural gas and associated natural gas liquids reserves, EnCana now owns about 75 percent of the Jonah field in southwest Wyoming.

"Our move into the U.S. Rockies, started less than 30 months ago, continues to exceed our expectations for growth and potential. This is currently our highest growth region and we have clearly demonstrated our ability to add value to acquisitions with drill bit success. During the third quarter, production from the region averaged 550 million cubic feet per day, a remarkable achievement in such a short time frame," said Randy Eresman, President of EnCana's Onshore North America division.

To help mitigate the impact of gas transportation limitations from the U.S. Rockies to markets, EnCana has established a series of fixed price differentials from the NYMEX index at an average of US$0.47 per thousand cubic feet on effectively all of EnCana's U.S. Rockies winter production and on approximately 400 million cubic feet per day from April 2003 to October 2007.

Greater Sierra on target EnCana continues its successful exploration and development program in the Greater Sierra area of northeast British Columbia, drilling 29 wells during the summer season. Initial production rates continue to improve and EnCana has lowered drilling costs this year by more than 15 percent.

"The cost and operational efficiencies achieved to date are really just a starting point. As we gain a greater understanding of the geology and refine our drilling techniques over this large property, we expect to reduce costs further and continue generating strong returns from this high growth area," Eresman said.

Canada's first commercial coal bed methane project underway EnCana has started development of Canada's first commercial coal bed methane project, drilling the first of 32 anticipated net wells on EnCana's contiguous fee simple lands east of Calgary. This demonstration-scale project is designed to verify the commercial potential of natural gas production from coal seams located under Canada's prairies. During the pilot project, EnCana drilled about 76 net wells. The pilot is currently producing gas from 14 wells, which have production that ranges from approximately 30 thousand to approximately 250 thousand cubic feet per day. EnCana continues to evaluate the potential of coal bed methane at other projects located in the Elk Valley of southeast B.C. and the Grizzly Valley in northeast B.C.

Oil and natural gas liquids production rise Daily production of conventional oil and natural gas liquids from EnCana's Onshore North America division averaged 169,069 barrels per day in the third quarter of 2002, a 5 percent increase from pro forma results of the third quarter of 2001. This production increase has come largely from two Western Canadian properties, EnCana's Foster Creek steam-assisted gravity drainage ("SAGD") project in northeast Alberta and Suffield in southern Alberta.

EnCana's two SAGD projects growing production EnCana's inaugural commercial SAGD project, at Foster Creek in northeast Alberta, averaged approximately 14,000 barrels of daily production during the third quarter. This production rate is lower than originally forecast as the company works to achieve optimum production efficiency and ramps up the facilities to full operation. While facilities start up of this industry-leading SAGD project has taken longer than originally anticipated, current well performance is exceeding design parameters. Production from Foster Creek is expected to average 20,000 barrels per day in 2003. Given EnCana's technical success at Foster Creek, expansion is underway to increase production by an anticipated 10,000 barrels per day to about 30,000 barrels per day, which the Company expects to reach in 2004. Initial production has also started from EnCana's second SAGD project at Christina Lake in northeast Alberta, where the learning experience from Foster Creek is being applied.

Syncrude volumes reach record levels, costs down substantially EnCana's share of Syncrude production during the third quarter of 2002 averaged a record 36,039 barrels per day, up 25 percent from the same period in 2001. Operating costs averaged $13.38 per barrel, down substantially from levels earlier this year as a result of increased production volumes. Production rose as the world's largest oil sands plant resumed full production following the completion of planned maintenance and an upgrade of one of Syncrude's coker units. EnCana expects average operating costs of approximately $19 per barrel for 2002. Syncrude's production for 2003 is estimated at 31,000 to 34,000 barrels per day, with a slight improvement in non-energy related operating costs.

Offshore and International Operations

Ecuador – strong third quarter sales Oil production in Ecuador, which is limited by existing pipeline capacity, averaged 52,344 barrels of oil per day in the third quarter. Daily oil sales averaged 55,579 barrels, up eight percent from the same period one year earlier due to increased access to the existing SOTE pipeline combined with higher volumes shipped from port. The OCP Pipeline project is about 70 percent complete, with first oil shipments expected in mid 2003. EnCana has current productive capability of more than 80,000 barrels per day in Ecuador and is targeting production of between 80,000 and 100,000 barrels per day by late 2003 following the planned opening of OCP. Reaching the higher production targets requires the Government of Ecuador's approval of EnCana's expansion plans onto lands located adjacent to the Company's existing producing properties. Additionally, a number of outstanding issues, including resolution of the industry's dispute over value added tax assessments, may impact EnCana's timing for reaching production of the forecast 100,000 barrels per day. EnCana participated in drilling three successful exploration discoveries during the third quarter on its Ecuador Blocks.

U.K. North Sea – Buzzard pre-engineering contract awarded Development work on one of the largest oil discoveries in the U.K. North Sea in the past 25 years is moving ahead with the awarding of a major engineering contract for the concept definition and project specification for development and production facilities at the Buzzard oil field. Evaluation of the appraisal drilling continues and EnCana plans to explore both possible field extensions and adjacent geological structures. Buzzard is estimated to contain between 800 million and 1.1 billion barrels of oil-in-place and recoverable reserve estimates are currently being updated. EnCana owns 35 and 45 percent of the two blocks where Buzzard is located.

East Coast of Canada – Regulatory review and engineering continues on Deep Panuke gas project The National Energy Board ("NEB") and the Canada-Nova Scotia Offshore Petroleum Board ("CNSOPB") are proceeding with a full review of EnCana's development plan for the Deep Panuke natural gas project, located on the Scotian Shelf offshore Nova Scotia. Recent plans by both regulatory boards to hold a single hearing for review are encouraging. The regulatory hearing for Deep Panuke is expected to start in the first quarter of 2003, with a decision anticipated by mid 2003. EnCana had been working towards a 2005 target start date for the project. However, given a longer than anticipated *Canadian Environmental Assessment Act* ("CEAA") comprehensive study report ("CSR") process, it is unlikely that the project will be operational by that time. The CSR has been filed with the federal minister of the environment and EnCana is awaiting a firm date for the hearing. The Company is also examining newly acquired seismic and related exploration opportunities in the vicinity of Deep Panuke that could enhance project economics. EnCana continues to promote timely regulatory approvals that balance the needs of the Company, the public and the regulators. Once the NEB and CNSOPB have ruled on the Deep Panuke application, EnCana will review the regulatory decisions, including all conditions for approval, and make a decision on project sanction.

Offshore and New Ventures Exploration

Canada's East Coast – a gas discovery and more drilling this winter The Annapolis G-24 deep water exploration well, located about 350 kilometres southeast of Halifax offshore Nova Scotia, encountered approximately 30 metres of net natural gas pay over several zones. EnCana has a 26 percent interest in the well operated by Marathon Oil Company. Further plans to assess the potential of this discovery are under development.

The Eirik Raude, a highly sophisticated, deep water drilling rig, has completed its inaugural sea trials in preparation for drilling the first of three EnCana exploration wells starting this fall. This dynamically positioned, semi-submersible rig is designed for the harsh environment of the North Atlantic and capable of drilling in 3,000 metres of water. EnCana plans to use the Eirik Raude to drill the Torbrook prospect starting this month offshore Nova Scotia, followed by two wells offshore Newfoundland, in the Flemish Pass, that will be operated by Petro-Canada.

Gulf of Mexico – Tahiti appraisal underway, more exploration planned this winter Two appraisal wells are planned this winter to evaluate the Tahiti oil discovery in the Gulf of Mexico. Operator ChevronTexaco has estimated that Tahiti holds 400 million to 500 million barrels of recoverable oil. The Tahiti find, announced in June, is the second of a four-well program that will earn EnCana a 25 percent interest in 71 ChevronTexaco-operated blocks in the Mississippi Fanfold Belt in the Gulf of Mexico. EnCana owns a 25 percent interest in Tahiti, located in the deep water Green Canyon Block 640. The third of the four ChevronTexaco wells – the Sierra well located in Atwater Valley Block 187 – is expected to reach total depth before year-end. EnCana is also participating in a four-well farm-in program with Conoco. The third well in that program, Spa, was drilled in the Walker Ridge Block 285 during the third quarter but did not encounter commercial quantities of hydrocarbons. Conoco is currently drilling the fourth well in the program, the Voss prospect in Keathley Canyon Block 511. Voss is expected to reach total depth by year-end and is adjacent to blocks where EnCana holds options to participate in additional exploration.

Midstream and Marketing

Pipeline sale interest strong A variety of parties have expressed strong interest in purchasing EnCana's ownership in two major oil pipelines – the 100-percent-owned Express Pipeline System and the 70-percent-owned Cold Lake Pipeline System. In combination, these oil transportation systems deliver Canada's growing oil sands production to Canadian and U.S. refineries. Since the sale is expected to be completed by year-end, financial information related to the Express and Cold Lake pipeline systems has been presented as Discontinued Operations in the third quarter unaudited consolidated financial statements.

Gas storage expansions underway in Alberta and California EnCana is further expanding North America's largest independent network of underground natural gas storage reservoirs. In southeastern Alberta, EnCana recently announced the commencement of development of the Countess gas storage facility, which is designed to store up to 40 billion cubic feet of gas. In northern California, construction is underway to double the size of EnCana's Wild Goose storage facility to an estimated 29 billion cubic feet of capacity. These two projects, which are anticipated to be completed in 2005, would increase EnCana's continental storage capacity to about 200 billion cubic feet. At that time, the network's total peak withdrawal capacity is expected to grow to approximately four billion cubic feet per day.

"EnCana is growing its storage capacity at a time when demand for gas storage is increasing. As North America's leading independent gas producer, our storage network assists us in managing our inventory of produced gas, timing our sales to meet consumer and seasonal demand and optimizing the value of our production. It also provides storage services to Canadian and U.S. producers and marketers for managing gas supplies and sales," said Bill Oliver, President of EnCana's Midstream and Marketing division.

Financial Strength

EnCana's financial position is among the strongest of upstream independents. At September 30, 2002, the Company's debt-to-capitalization ratio was 39:61 (all preferred securities included as debt). Third quarter core capital investment and acquisitions were $1,507 million. Dispositions were $133 million, resulting in net capital investment of $1,374 million. EnCana maintains strong investment grade ratings from the major bond rating services: Dominion Bond Rating Service Limited, A(low), Moody's Investors Service, Baa1, and Standard and Poor's Ratings Services, A-. On October 2, 2002, EnCana issued C$300 million in medium term notes that bear an annual interest rate of 5.30 percent.

IMPORTANT NOTICE

NOTE: This third quarter report includes two sets of financial statements:

1. EnCana's actual financial statements, which reflect results as illustrated in the table below.

EnCana actual financial statements

Q3 2002	Q3 2001	Nine months 2002	Nine months 2001
EnCana (PCE & AEC)	PCE Alone	EnCana (PCE & AEC) for Q2 & Q3, plus PCE alone Q1	PCE alone

2. EnCana's pro forma nine month financial statements, which reflect results as if the merger of PanCanadian Energy Corporation ("PCE") and Alberta Energy Company Ltd. ("AEC") had occurred at the beginning of 2002.

This document and Alberta Energy Company Ltd.'s third quarter 2002 financial statements are filed on Sedar and posted on www.sedar.com.

This document and EnCana's supplemental information are posted on the Company Web site, www.encana.com.

EnCana Corporation

EnCana is one of the world's leading independent oil and gas companies with an enterprise value of approximately C$30 billion. EnCana is North America's largest independent natural gas producer and gas storage operator. Ninety percent of the Company's assets are in four key North American growth platforms. EnCana is the largest producer and landholder in Western Canada and is a key player in Canada's emerging offshore East Coast basins. In the U.S., EnCana is one of the largest gas explorers and producers in the Rocky Mountain states and has a strong position in the deepwater Gulf of Mexico. The Company has two key high potential international growth platforms: EnCana is the largest private sector oil producer in Ecuador and is the operator of a very large oil discovery in the U.K. central North Sea. The Company also conducts high upside potential New Ventures exploration in other parts of the world. EnCana is driven to be the industry's best-in-class benchmark in production cost, per-share growth and value creation for shareholders. EnCana common shares trade on the Toronto and New York stock exchanges under the symbol "ECA."

ADVISORY – In the interests of providing EnCana shareholders and potential investors with information regarding EnCana, including management's assessment of EnCana's future plans and operations, certain statements contained in this third quarter report are forward-looking statements within the meaning of the "safe harbour" provisions of the *United States Private Securities Litigation Reform Act* of 1995. Forward-looking statements in this report include, but are not limited to, EnCana's internal projections, expectations or beliefs concerning future operating results, and various components thereof; future economic performance; the production and growth potential of its various assets, including assets in the U.S. Rockies, Greater Sierra, offshore Canada's East Coast, the U.K. central North Sea and Ecuador; the anticipated oil and natural gas prices for the remainder of 2002; the ability to achieve 2002 and 2003 sales growth targets; the sources and deployment of expected capital in 2002; the projected annual post-merger synergies in 2003; the anticipated completion in 2005 of the Countess and Wild Goose gas storage projects, and the projected gas storage capacity in 2005; the timing of regulatory review regarding Deep Panuke and the projected production date from the Deep Panuke project; the success of future drilling prospects; potential exploration; the potential success of certain projects such as SAGD (including in 2003 and 2004), coal bed methane, the OCP Pipeline and Syncrude and the expected rates of return from such projects; the ability to sell the Cold Lake and Express pipeline interests, the price realized on such sales and the timing of such sales; and the potential success of other exploratory wells in the Gulf of Mexico, offshore Canada's East Coast and the U.K. central North Sea.

Readers are cautioned not to place undue reliance on forward-looking statements, as there can be no assurance that the plans, intentions or expectations upon which they are based will occur. By their nature, forward-looking statements involve numerous assumptions, known and unknown risks and uncertainties, both general and specific, that contribute to the possibility that the predictions, forecasts, projections and other forward-looking statements will not occur, which may cause the Company's actual performance and financial results in future periods to differ materially from any estimates or projections of future performance or results expressed or implied by such forward-looking statements. These risks and uncertainties include, among other things: volatility of oil and gas prices; fluctuations in currency and interest rates; product supply and demand; market competition; risks inherent in the Company's marketing operations; imprecision of reserve estimates; the Company's ability to replace and expand oil and gas reserves; its ability to generate sufficient cash flow from operations to meet its current and future obligations; its ability to access external sources of debt and equity capital; the risk that the anticipated synergies to be realized by the merger of AEC and PanCanadian will not be realized; costs relating to the merger of AEC and PanCanadian being higher than anticipated and other risks and uncertainties described from time to time in the reports and filings made with securities regulatory authorities by EnCana and its indirect wholly-owned subsidiary, AEC. Although EnCana believes that the expectations represented by such forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct. Readers are cautioned that the foregoing list of important factors is not exhaustive. Furthermore, the forward-looking statements contained in this report are made as of the date of this report, and EnCana does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise. The forward-looking statements contained in this report are expressly qualified by this cautionary statement.

Further information on EnCana Corporation and Alberta Energy Company Ltd. is available on the Company's Web site, www.encana.com, or by contacting:

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EnCana Corporation
Pro Forma Consolidated Statement of Earnings

(Unaudited)

($ millions, except per share amounts)	**EnCana** Nine Months Ended September 30, 2002	**AEC** Three Months Ended March 31, 2002	**Pro Forma Adjustments** Note 1	**EnCana Pro Forma Consolidated**
Revenues, Net of Royalties and Production Taxes				
Upstream	$ 3,828	$ 844	$ (141)	$ 4,531
Midstream and Marketing	2,788	358	141	3,287
Other	3	–	–	3
	6,619	1,202	–	7,821
Expenses				
Transportation and selling	383	103	–	486
Operating	981	202	–	1,183
Purchased product	2,317	406	–	2,723
Administrative	111	24	–	135
Interest, net	242	61	9	312
Foreign exchange	(24)	(1)	–	(25)
Depreciation, depletion and amortization	1,410	302	45	1,757
Earnings Before the Undernoted	1,199	105	(54)	1,250
Income tax expense (recovery)	379	39	(23)	395
Distributions on Subsidiary Preferred Securities, net of tax	11	16	(5)	22
Net Earnings from Continuing Operations	809	50	(26)	833
Net Earnings from Discontinued Operations	(14)	6	–	(8)
Net Earnings	795	56	(26)	825
Distributions on Preferred Securities, Net of Tax	2	–	–	2
Net Earnings Attributable to Common Shareholders	$ 793	$ 56	$ (26)	$ 823

Earnings per Common Share	
Continuing operations	
Basic	$ 1.75
Diluted	$ 1.72
Net earnings	
Basic	$ 1.74
Diluted	$ 1.70

EnCana Corporation

Pro Forma Consolidated Statement of Cash Flow from Operations

(Unaudited)

($ millions, except per share amounts)	**EnCana** Nine Months Ended September 30, 2002	**AEC** Three Months Ended March 31, 2002	**Pro Forma Adjustments** Note 1	**EnCana Pro Forma Consolidated**
Operating Activities				
Net earnings from continuing operations	$ 809	$ 50	$ (26)	$ 833
Depreciation, depletion and amortization	1,410	302	45	1,757
Future income taxes	271	13	(19)	265
Other	(160)	9	–	(151)
Cash Flow from Continuing Operations	2,330	374	–	2,704
Cash Flow from Discontinued Operations	19	16	–	35
Cash Flow	$ 2,349	$ 390	$ –	$ 2,739
Cash Flow per Common Share from Continuing Operations				
Basic				$ 5.70
Diluted				$ 5.59
Cash Flow per Common Share				
Basic				$ 5.78
Diluted				$ 5.66

EnCana Corporation

Note to Pro Forma Consolidated Financial Statements

September 30, 2002 *(Unaudited)*

1. BASIS OF PRESENTATION

These unaudited Pro Forma Consolidated Statement of Earnings and Consolidated Statement of Cash Flow have been prepared for information purposes using information contained in the following:

(a) EnCana's unaudited consolidated financial statements for the nine months ended September 30, 2002

(b) AEC's unaudited consolidated financial statements for the three months ended March 31, 2002.

The pro forma adjustments include adjustments for financial statement presentation of segmented financial information. To be consistent with EnCana's segmented presentation, revenues associated with AEC's purchased gas activity have been reclassified from Upstream revenue.

All pro forma adjustments related to the purchase price allocation have been based upon the Business Combination information disclosed in Note 3 of the September 30, 2002 unaudited Consolidated Financial Statements of EnCana and assume that the transaction occurred on January 1, 2002.

Pro forma adjustments made in the unaudited Consolidated Statement of Earnings and unaudited Consolidated Statement of Cash Flow relate to (i) the recording of interest expense on the Capital Securities of AEC, (ii) the recording of Depreciation, depletion and amortization on the increase in the carrying value of Capital Assets resulting from the acquisition which has been allocated to capital assets that are subject to depreciation, depletion and amortization and (iii) the recording of the future income tax benefits related to these additional expenses.

These unaudited Pro Forma Consolidated Financial Statements may not be indicative of the results that actually would have occurred if the events reflected therein had been in effect on the dates indicated or of the results that may be obtained in the future.

SPECIAL NOTE REGARDING FORWARD-LOOKING INFORMATION

In the interest of providing EnCana Corporation ("EnCana" or the "Company"), formerly PanCanadian Energy Corporation ("PanCanadian"), shareholders and potential investors with information regarding the Company, certain statements throughout this Interim Management's Discussion and Analysis ("MD&A") constitute forward-looking statements within the meaning of the United States *Private Securities Litigation Reform Act* of 1995. Forward-looking statements are typically identified by words such as "anticipate", "believe", "expect", "plan", "intend" or similar words suggesting future outcomes or statements regarding an outlook. Forward-looking statements in this MD&A include, but are not limited to, statements with respect to: the Company's operating costs; oil and gas prices; the Company's crude oil, liquids and gas sales; the Company's cash flow and net earnings; the Company's production levels; the impact of hedges on the Company's revenues; capital investment levels; the Company's sources of funding for capital investments; the development of new natural gas storage facilities and increases in the Company's gas storage capacity; the impact of natural gas storage levels on natural gas prices; the Company's effective tax rate for 2002; the execution of share purchases under the Company's normal course issuer bid program; the volatility of world energy prices; the timing and extent of the Company's production growth from capital expenditures; the anticipated timing and results of discontinuing the Houston-based merchant energy operation and of the proposed disposition of the Express and Cold Lake pipeline interests; and future operating results and various components thereof.

Readers are cautioned not to place undue reliance on forward-looking information, as there can be no assurance that the plans, intentions or expectations upon which it is based will occur. By its nature, forward-looking information involves numerous assumptions, known and unknown risks and uncertainties, both general and specific, that contribute to the possibility that the predictions, forecasts, projections and other forward-looking statements will not occur. Although the Company believes that the expectations represented by such forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct. Some of the risks and other factors which could cause results to differ materially from those expressed in the forward-looking statements contained in this MD&A include, but are not limited to: volatility of crude oil and natural gas prices, fluctuations in currency and interest rates, product supply and demand, market competition, risks inherent in the Company's North American and foreign oil and gas and midstream operations, risks inherent in the Company's marketing operations, imprecision of reserves estimates, the Company's ability to replace and expand oil and gas reserves, the Company's ability to either generate sufficient cash flow from operations to meet its current and future obligations or obtain external sources of debt and equity capital, general economic and business conditions, the Company's ability to enter into or renew leases, the timing and costs of well and pipeline construction, the Company's ability to make capital investments and the amounts of capital investments, imprecision in estimating the timing, costs and levels of production and drilling, the results of exploration and development drilling, imprecision in estimates of future production capacity, the Company's ability to secure adequate product transportation, uncertainty in the amounts and timing of royalty payments, imprecision in estimates of product sales, changes in environmental and other regulations, political and economic conditions in the countries in which the Company operates including Ecuador, and such other risks and uncertainties described from time to time in the Company's reports and filings with the Canadian securities authorities and the United States Securities and Exchange Commission. Accordingly, the Company cautions that events or circumstances could cause actual results to differ materially from those predicted. Statements relating to "reserves" or "resources" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions that the resources and reserves described can be profitably produced in the future. Readers are cautioned that the foregoing list of important factors is not exhaustive. Readers are further cautioned not to place undue reliance on forward-looking statements contained in this MD&A, which are made as of the date hereof, and the Company undertakes no obligation to update publicly or revise any forward-looking information, whether as a result of new information, future events or otherwise. The forward-looking statements contained in this MD&A are expressly qualified by this cautionary statement.

This Interim Management's Discussion and Analysis ("MD&A") for EnCana Corporation ("EnCana" or the "Company") should be read in conjunction with the unaudited interim consolidated financial statements for the nine months ended September 30, 2002 and September 30, 2001 and the audited consolidated financial statements and MD&A of PanCanadian Energy Corporation ("PanCanadian"), the Company's predecessor, for the year ended December 31, 2001.

CONSOLIDATED OVERVIEW

On April 5, 2002, PanCanadian and Alberta Energy Company Ltd. ("AEC") completed the merger of their two companies, creating EnCana Corporation. The companies satisfied all closing conditions, including receipt of approvals from shareholders of PanCanadian, shareholders and optionholders of AEC, and the Court of Queen's Bench of Alberta. Under the terms of the merger, AEC shareholders received 1.472 EnCana common shares for each AEC common share owned. For further information with respect to the merger transaction, refer to Note 3 to the unaudited interim consolidated financial statements ("Consolidated Financial Statements").

The Consolidated Financial Statements include the results of AEC from the closing date of the merger. As such, the year-to-date amounts reflect nine months of PanCanadian results combined with the six months of post merger AEC results. The year-to-date comparisons are based solely on the 2001 results of PanCanadian.

EnCana's third quarter cash flow from continuing operations was $1,027 million, or $2.13 per diluted common share ("per share"), compared with $562 million, or $2.15 per share, last year. Third quarter net earnings from continuing operations were $184 million, or $0.38 per share, compared with $277 million, or $1.05 per share, in the same quarter of 2001. In addition to weaker Western Canada and U.S. Rockies regional ("regional") natural gas prices, third quarter earnings were also impacted by an after-tax foreign exchange loss of $145 million, or $0.30 per share, that related to the translation of U.S. dollar denominated long-term debt.

As discussed in Note 2 to the Consolidated Financial Statements, the Company is required to translate long-term debt denominated in U.S. dollars into Canadian dollars at the period-end exchange rate with any resultant adjustment recorded in the Consolidated Statement of Earnings. In order to provide shareholders and potential investors with information, which clearly presents the effect of the translation of the outstanding U.S. dollar debt on the Company's results, the following table has been prepared:

	2002			
($ millions)	Q1	Q2	**Q3**	**Year-to-Date**
Net earnings, as reported	$ 133	$ 458	**$ 204**	**$ 795**
Deduct: Foreign exchange gain (loss) on translation of U.S. dollar debt (after-tax)*	(1)	163	**(145)**	**17**
Earnings, excluding foreign exchange on translation of U.S. dollar debt	$ 134	$ 295	**$ 349**	**$ 778**
($ per Common Share diluted)				
Net earnings per Common Share – diluted, as reported	$ 0.51	$ 0.97	**$ 0.42**	**$ 1.96**
Deduct: Foreign exchange gain (loss) on translation of U.S. dollar debt (after-tax)*	–	0.35	**(0.30)**	**0.04**
Earnings, excluding foreign exchange on translation of U.S. dollar debt per Common Share – diluted	$ 0.51	$ 0.62	**$ 0.72**	**$ 1.92**

* As this is an unrealized gain (loss), there is no impact on cash flow.

For the nine months ended September 30, 2002, net earnings from continuing operations of $809 million, or $1.99 per share, were lower in comparison with $1,165 million, or $4.44 per share, in the corresponding period of 2001. Cash flow from continuing operations was $2,330 million, or $5.76 per share, compared with $1,875 million, or $7.16 per share, in the same period last year. The decline in year-to-date net earnings was primarily a result of significantly weaker regional market prices for natural gas. The effect of the lower regional natural gas prices was partially offset by an increase in sales volumes resulting from the merger of the Company with AEC in April 2002.

	Three Months Ended September 30		Nine Months Ended September 30	
Consolidated Financial Summary *($ millions, except per share amounts)*	**2002**	2001	**2002**	2001
Revenues, net of royalties and production taxes	**$ 2,882**	$ 1,139	**$ 6,619**	$ 3,950
Net earnings from continuing operations	**184**	277	**809**	1,165
– per share basic	**0.38**	1.07	**2.03**	4.54
– per share diluted	**0.38**	1.05	**1.99**	4.44
Net earnings	**204**	275	**795**	1,197
– per share basic	**0.43**	1.07	**1.99**	4.67
– per share diluted	**0.42**	1.04	**1.96**	4.56
Cash flow from continuing operations	**1,027**	562	**2,330**	1,875
– per share basic	**2.15**	2.19	**5.86**	7.33
– per share diluted	**2.13**	2.15	**5.76**	7.16
Cash flow	**1,022**	560	**2,349**	1,920
– per share basic	**2.14**	2.19	**5.90**	7.51
– per share diluted	**2.12**	2.13	**5.80**	7.34

On August 1, 2002, the Company announced that one of its U.S. subsidiaries had further strengthened its position in the U.S. Rocky Mountain region through the purchase of producing and non-producing assets in the Jonah field, in southwest Wyoming, for approximately $539 million. The acquisition included developed and undeveloped reserves and increased EnCana's interest in the Jonah field production from approximately 50 percent to approximately 75 percent.

On April 24, 2002, the Company adopted formal plans to exit from its Houston-based merchant energy operation, which was included in the Midstream and Marketing segment. The wind-down of this operation has been substantially completed. At September 30, 2002, an after-tax loss of $46 million has been recorded, which included the expected costs associated with completing the wind-down of the Houston-based merchant energy operation later this year. Upon review of additional information related to 2001 sales and purchases of natural gas by this U.S. operation, the Company determined that certain revenues and expenses should have been reflected in the financial statements in 2001 on a net basis as described in Note 5 to the Consolidated Financial Statements and as previously presented in the Company's unaudited interim consolidated financial statements for the first quarter of 2002. Certain of these 2001 natural gas sale and purchase transactions may be characterized as so-called "round-trip" transactions. The Company has received requests for information from several U.S. governmental agencies regarding these round-trip transactions. In addition, in connection with its investigation of Reliant Resources, Inc. and Reliant Energy, Inc., the U.S. Securities and Exchange Commission has issued a subpoena to the Company to produce all documents concerning round-trip transactions with those corporations. The Company is cooperating fully in responding to all of these requests.

On July 9, 2002, the Company announced plans to dispose of its interests in two major crude oil pipeline systems. The proposed disposition includes the Company's indirect 100 percent interest in the Express Pipeline System and its indirect 70 percent interest in the Cold Lake Pipeline System. During the third quarter, progress was made in regards to the planned disposition and the Company expects to complete a sale later in the fourth quarter. It is anticipated that, upon the proposed disposition, the proceeds will initially be used to reduce debt prior to being re-deployed into other strategic initiatives.

The merchant energy and pipeline operations described above have both been accounted for as discontinued operations as described in Note 5 to the Consolidated Financial Statements.

BUSINESS ENVIRONMENT

	Three Months Ended September 30		Nine Months Ended September 30	
	2002	2001	**2002**	2001
Average AECO Price *($ per thousand cubic feet)*	**3.25**	3.92	**3.67**	7.30
Average NYMEX Price *(US$ per million British thermal units)*	**3.26**	2.98	**3.01**	5.01
WTI Average *(US$ per barrel)*	**28.25**	26.60	**25.45**	27.77
WTI-Bow River Differential *(US$ per barrel)*	**5.38**	7.16	**5.35**	9.99
Oriente Differential (Ecuador) *(US$ per barrel)*	**4.35**	5.22	**4.28**	7.35
U.S./Canadian dollar exchange rate *(US$)*	**0.640**	0.647	**0.637**	0.650

High levels of natural gas in storage, resulting from decreased demand, continued to have a negative impact on natural gas prices during the quarter. In the third quarter, the AECO index price per thousand cubic feet averaged $3.25 compared with $3.92 in the same quarter of 2001. The average AECO index price for the nine months ended September 30, 2002 of $3.67 per thousand cubic feet was down approximately 50 percent in comparison to the same period last year. The NYMEX to AECO basis differential has widened through the year as it averaged US$0.29 per million British thermal units in the first quarter of 2002 compared with US$1.17 per million British thermal units in the third quarter, as a result of pipeline maintenance programs, less demand in the U.S. Pacific Northwest due to higher hydro electric generation and high levels of gas in storage in the western U.S.

World crude oil prices maintained their upward trend during the third quarter of 2002. The benchmark West Texas Intermediate ("WTI") crude oil price averaged US$28.25 per barrel in the third quarter, up six percent from the same quarter last year. The increase in the quarter largely reflected a "war premium" resulting from worries over escalating conflicts with Iraq. For the year to date, the average WTI crude oil price was US$25.45 per barrel, a decrease of eight percent from the same period of 2001, reflecting the negative impact of low first quarter prices.

The differential between heavy and light crude oil prices continued to benefit from improvements in the supply/demand balance for heavy oil. The WTI-Bow River differential averaged US$5.38 per barrel in the third quarter and US$5.35 per barrel in the nine months, a narrowing of 25 percent and 46 percent from the respective periods of 2001.

RESULTS OF OPERATIONS

Upstream – Onshore North America and Offshore and International

	Three Months Ended September 30							
	2002				2001			
Financial Results *($ millions)*	**Produced Gas and NGLs**	**Conventional Crude Oil**	**Syncrude**	**Total**	Produced Gas and NGLs	Conventional Crude Oil	Syncrude	Total
Revenues								
Gross revenue	**$ 1,143**	**$ 662**	**$ 143**	**$ 1,948**	$ 595	$ 311	$ –	$ 906
Royalties and production taxes	**138**	**118**	**2**	**258**	29	33	–	62
Revenues, net of royalties and production taxes	**1,005**	**544**	**141**	**1,690**	566	278	–	844
Expenses								
Transportation and selling	**92**	**34**	**2**	**128**	30	10	–	40
Operating	**141**	**134**	**44**	**319**	52	61	–	113
Depreciation, depletion and amortization	**–**	**–**	**–**	**584**	–	–	–	195
Upstream income	**$ 772**	**$ 376**	**$ 95**	**$ 659**	$ 484	$ 207	$ –	$ 496
Capital expenditures (excludes dispositions)				**$ 1,462**				$ 501

	Nine Months Ended September 30							
	2002				2001			
Financial Results *($ millions)*	**Produced Gas and NGLs**	**Conventional Crude Oil**	**Syncrude**	**Total**	Produced Gas and NGLs	Conventional Crude Oil	Syncrude	Total
Revenues								
Gross revenue	**$ 2,681**	**$ 1,521**	**$ 234**	**$ 4,436**	$ 2,205	$ 831	$ –	$ 3,036
Royalties and production taxes	**347**	**258**	**3**	**608**	148	96	–	244
Revenues, net of royalties and production taxes	**2,334**	**1,263**	**231**	**3,828**	2,057	735	–	2,792
Expenses								
Transportation and selling	**210**	**67**	**3**	**280**	85	28	–	113
Operating	**312**	**319**	**112**	**743**	138	192	–	330
Depreciation, depletion and amortization	**–**	**–**	**–**	**1,329**	–	–	–	558
Upstream income	**$ 1,812**	**$ 877**	**$ 116**	**$ 1,476**	$ 1,834	$ 515	$ –	$ 1,791
Capital expenditures (excludes dispositions)				**$ 3,255**				$ 1,243

Revenue Variances for 2002 Compared to 2001 *($ millions)*	Three Months Ended September 30 Price	Volume	Merger Volume*	Total	Nine Months Ended September 30 Price	Volume	Merger Volume*	Total
Produced gas and NGLs	$ (72)	$ (3)	$ 623	$ 548	$ (775)	$ 48	$ 1,203	$ 476
Conventional crude oil	23	(29)	357	351	38	(35)	687	690
Syncrude	–	–	143	143	–	–	234	234
Total gross revenue	$ (49)	$ (32)	$ 1,123	$ 1,042	$ (737)	$ 13	$ 2,124	$ 1,400

* Represents revenue from volumes added on account of the merger of the Company with AEC.

Revenues

The Company reports its segmented financial results showing revenue prior to all royalty payments, both cash and in-kind, consistent with Canadian disclosure practices for the oil and gas industry. Third quarter upstream gross revenue rose 115 percent, or $1,042 million, to $1,948 million compared with the same quarter in 2001. Upstream gross revenue for the year to date was $4,436 million, an improvement of 46 percent over the same period last year. Included in gross revenue is $168 million relating to the fair value of AEC's forward gas sales contracts recorded as part of the business combination on April 5, 2002. At September 30, 2002, the $168 million was fully amortized and recorded as additional gas revenue, $91 million of which was recorded in the third quarter. These amounts have been excluded for the purposes of discussing realized prices.

Produced Gas and NGLs

Sales of produced gas and natural gas liquids contributed $1,143 million to revenues in the third quarter of 2002, an increase of $548 million over the same quarter of 2001. Produced gas sales volumes in the quarter were 2,688 million cubic feet per day, a 156 percent improvement over the same period of 2001, primarily resulting from the merger with AEC. NGL sales in the third quarter were 22,927 barrels per day, up 12 percent from the third quarter of 2001, also a result of the merger with AEC. Weaker regional natural gas prices partly offset the Company's growth in natural gas sales volumes. For the three months ended September 30, 2002, realized natural gas prices averaged $3.56 per thousand cubic feet, down from $5.57 per thousand cubic feet in the same period of 2001. Natural gas revenues in the quarter were $86 million higher as the result of a gain from currency and commodity hedging activities. This contrasted with a $188 million increase in the same quarter of last year.

Produced gas and natural gas liquids revenues for the year to date were $2,681 million, a 22 percent increase over the same period in 2001. The higher results largely reflect the growth in the Company's sales resulting from the merger and were partially offset by a decrease in realized natural gas prices which, at $3.75 per thousand cubic feet, were down 47 percent from the corresponding period of last year. During the first nine months of 2002, natural gas sales volumes averaged 2,124 million cubic feet per day compared with 1,045 million cubic feet per day in the same period of 2001. Hedging activities in the first nine months increased natural gas revenues by $95 million in comparison to a hedging gain of $112 million for the same period last year.

Conventional Crude Oil

Third quarter revenues from the sale of conventional crude oil were $662 million, an improvement of $351 million, or 113 percent, over the same quarter in 2001. The increase in revenues is the result of additional sales volumes from the merger of the Company with AEC in combination with higher world oil prices. Commodity and currency hedging in the quarter resulted in a $12 million loss, which compares to a $4 million loss in the respective period of 2001.

Onshore North America conventional crude oil sales volumes averaged 146,142 barrels per day during the third quarter compared with 91,933 barrels per day in the same quarter of 2001. Additional merger-related sales volume was the primary factor contributing to the increase. The Company's realized price from Onshore North America crude averaged $31.49 per barrel in the quarter, an improvement over an average price of $31.40 per barrel in the same period last year.

Third quarter sales volumes from Offshore and International were 65,141 barrels per day, which compares to 12,669 barrels per day in the third quarter of 2001. The increase reflects the addition of Ecuador oil volumes, which helped to offset a reduction in the U.K. sales volumes. Realized crude oil prices on the Company's Offshore and International sales averaged $33.59 per barrel for Ecuador oil and $39.30 per barrel for U.K. oil. Comparatively, U.K. realized crude oil prices in the third quarter of last year averaged $32.05 per barrel.

Revenues from conventional crude oil for the year to date increased by 83 percent to $1,521 million compared with the same period last year. The improvement in gross revenues was attributable to the volumes added from the merger of the Company with AEC in combination with strengthened world oil prices and narrower heavy crude oil differentials. Sales volumes in the first nine months of 2002 averaged 175,448 barrels per day, an improvement of 74,220 barrels per day, or 73 percent, over the same period last year. Year-to-date realized crude oil prices from Onshore North America averaged $29.18 per barrel compared with $28.08 per barrel in the corresponding period of 2001. Hedging activities for the nine months ended September 2002 resulted in a hedging loss of $34 million, which compares to a hedging loss of $22 million in the first nine months of last year. Offshore and International conventional crude oil activities for the year to date had an average realized price of $35.72 per barrel in the U.K. compared with an average of $36.28 per barrel for the same period last year. The year to date realized price on Ecuador oil was $32.57 per barrel.

Syncrude

As a result of the merger, EnCana added Syncrude oil production to its Onshore North America upstream operating results. Third quarter Syncrude sales revenue showed improvement over the second quarter of 2002. Sales volumes averaged 36,039 barrels per day, up 48 percent, at an average realized price of $42.54 per barrel, a six percent improvement over the second quarter of 2002. Second quarter sales volumes were negatively impacted by the coker turnaround.

Royalties and Production Taxes

Excluding the impact of hedging, royalties and production taxes were 14 percent of revenues in the third quarter of 2002 compared with nine percent in the same quarter of last year. For the nine months ended September 30, 2002, this rate was also 14 percent, which compares with eight percent for the same period of 2001. The increased rate reflects the addition of AEC's production base, which decreases the Company's relative proportion of production attributable to fee land where only mineral taxes are payable.

Expenses

Transportation and selling costs were $128 million in the third quarter compared with $40 million in the third quarter of 2001. For the nine months ending September 30, 2002, these costs amounted to $280 million compared with $113 million in the corresponding period last year. Higher sales volumes in the quarter and the year to date are the principal factors contributing to the increase in these costs. For the purpose of the revenue variance discussion above, these costs have been netted against revenues in calculating the per unit realized prices for each commodity.

	Three Months Ended September 30		Nine Months Ended September 30	
Unit Operating Expenses* *($ per unit)*	**2002**	2001	**2002**	2001
Produced gas *(per thousand cubic feet)*	**$ 0.57**	$ 0.54	**$ 0.54**	$ 0.48
Conventional crude oil *(per barrel)*	**6.17**	6.36	**6.12**	6.95
Per barrel of oil equivalent**	**4.16**	4.20	**4.03**	4.19
Syncrude *(per barrel)*	**13.38**	–	**20.22**	–

* Excluding operating costs from Other Countries, as described in Note 4 to the Consolidated Financial Statements, and cost recoveries.

** Natural gas converted to barrel of oil equivalent at 6 thousand cubic feet = 1 barrel of oil equivalent.

Upstream operating expenses, excluding Syncrude operations, were $275 million in the quarter, an increase of $162 million over the same quarter of 2001. For the year to date, these expenses were $631 million compared with $330 million in the corresponding period last year. Additional production resulting from the merger with AEC was the primary factor contributing to the increase in costs. On a unit basis, conventional operating expenses for the third quarter were $4.16 per barrel of oil equivalent compared with $4.20 per barrel of oil equivalent in the same quarter last year. In the year to date, these expenses were $4.03 per barrel of oil equivalent, an improvement over $4.19 per barrel of oil equivalent in the first nine months of 2001. The improvement in unit operating expenses primarily reflects the impact of lower costs associated with conventional crude oil production.

Produced gas operating expenses for the third quarter were $0.57 per thousand cubic feet, up $0.03 per thousand cubic feet over the same period of 2001. Higher costs for plant turnarounds and increased processing fees related to non-operated production were the primary factors contributing to the increase. The year-to-date unit costs, impacted by the higher third quarter costs, were $0.54 per thousand cubic feet, up from $0.48 per thousand cubic feet in the first nine months of last year.

In the third quarter, unit operating costs for conventional crude oil were $6.17 per barrel compared with costs of $6.36 per barrel in the same period of 2001. Unit operating costs for the nine months ended September 30, 2002 were $6.12 per barrel, a reduction from $6.95 per barrel for the same period last year. The improvements in operating expenses for the quarter and the year to date are the result of lower per unit costs related to the added AEC production and lower electricity costs.

Costs arising from Syncrude production added $44 million to operating expenses in the quarter and $112 million in the year to date. Per unit costs related to Syncrude production in the third quarter were $13.38 per barrel, which compares with $30.47 in the second quarter when costs were higher than average as a result of the coker turnaround.

Depreciation, depletion and amortization charges totalled $584 million in the quarter and $1,329 million for the year to date compared with $195 million and $558 million in the respective periods last year. On a barrel of oil equivalent basis, depletion, depreciation and amortization expenses were $8.84 per barrel in the third quarter, a 22 percent increase relative to the same quarter of 2001. For the year to date, these charges amounted to $8.52 per barrel compared with $7.07 per barrel in the first nine months of last year. The higher costs primarily reflected the additional charges associated with the addition of the AEC assets.

Third quarter upstream capital expenditures, excluding dispositions, were $1,462 million, an increase of $961 million over the same quarter of last year. Year-to-date capital expenditures, excluding dispositions, were $3,255 million compared with $1,243 million in the corresponding period last year. The majority of the capital expenditures were directed towards exploration and development in the Onshore North America division through its expansion in the U.S. Rocky Mountain region, the Greater Sierra area of northeastern British Columbia and continued development in southeastern Alberta.

Midstream and Marketing

Financial Results* *($ millions)*	Three Months Ended September 30		Nine Months Ended September 30	
	2002	2001	**2002**	2001
Revenues	**$ 1,188**	$ 291	**$ 2,788**	$ 1,137
Expenses				
Transportation and selling	**48**	3	**103**	12
Operating	**75**	46	**238**	200
Purchased product	**1,041**	220	**2,317**	861
Depreciation and amortization	**14**	3	**45**	10
	$ 10	$ 19	**$ 85**	$ 54
Capital expenditures (excludes dispositions)	**$ 24**	$ 36	**$ 148**	$ 105

* Results of the Midstream and Marketing segment exclude financial results related to discontinued operations as described in Note 5 to the Consolidated Financial Statements.

In the three months ended September 30, 2002, revenues from continuing midstream operations were $179 million, an increase of $128 million over the same period last year. In the year to date, these revenues were $439 million, an improvement of $218 million over the first nine months of 2001. The increases were chiefly attributable to the addition of the AEC midstream assets, which primarily include gas storage facilities and natural gas processing, to the Company's existing midstream segment.

In the three months ended September 30, 2002, gross revenue from the Company's marketing activity totalled $1,009 million including $561 million from the sale of purchased crude oil and NGLs and $448 million from the sale of purchased natural gas. Purchased product expense for the same period included $540 million of purchased crude oil and NGLs and $429 million of purchased natural gas. The loss of $14 million from continuing operations for the quarter compared with a margin of $14 million in the same quarter of 2001. As part of the Company's marketing business, the Company purchases and takes delivery of product from others and delivers that product to customers under existing transportation arrangements not utilized for its own production. Market price declines in certain regional markets resulted in a loss on the sale of purchased product delivered into these markets under fixed transportation arrangements.

For the nine months ended September 30, 2002, gross revenue from the Company's marketing activity totalled $2,349 million including $1,283 million from the sale of purchased crude oil and NGLs and $1,066 million from the sale of purchased natural gas. Purchased product expense for the same period included $1,228 million of purchased crude oil and NGLs and $966 million of purchased natural gas. Results for the nine months reflect the addition of volumes related to the merger with AEC. For the year to date, marketing activity from continuing operations resulted in a margin of $40 million, an increase of $9 million from the prior year. This increase is the result of the additional AEC purchased gas activity resulting from the merger and purchased crude oil activity resulting from a marketing agreement with another producer.

As a result of the substantial completion in the third quarter of the wind-down of the Houston-based merchant energy operation, the Company reviewed its accounting for the continuing marketing operations and determined that such operations will not follow mark-to-market accounting. This change to accounting for continuing marketing operations was adopted prospectively at the end of the third quarter.

In the third quarter, depreciation and amortization expenses for the division rose $11 million to $14 million compared with the same quarter last year. These charges totalled $45 million for the year to date compared with $10 million in the first nine months of 2001. The growth in the segment asset base resulting from the addition of AEC's midstream assets is the primary factor contributing to the increase in depreciation and amortization expenses.

Third quarter capital expenditures of $24 million were down from $36 million in the same quarter last year. Capital expenditures in the year to date were higher at $148 million compared with $105 million in the same period of 2001. The 2002 expenditures related primarily to ongoing improvements to midstream facilities. Capital expenditures in the first nine months of 2001 were principally due to the construction of two power plants in Alberta, which were commissioned in 2001.

The construction of the 450,000 barrel per day OCP pipeline in Ecuador is continuing on target for completion in the third quarter of 2003. It is expected that restricted transportation service at approximately 220,000 barrels per day will be available by the middle of 2003. To date, $27 million has been invested related to the Company's 31.4 percent equity interest in the pipeline project.

On October 17, 2002, EnCana announced plans to develop a new natural gas storage facility in southeastern Alberta that is anticipated will store up to 40 billion cubic feet of gas. On completion of the development, the Countess gas storage facility is expected to increase the Company's Western Canada gas storage capacity by approximately 40 percent to more than 135 billion cubic feet.

Corporate

Administrative expenses in the third quarter were $50 million, an increase of $14 million over the same period of 2001. In comparison with 2001, administrative expenses for the year to date were up $34 million to $111 million. The higher expenses are primarily attributable to the increased size of the Company as a result of the merger with AEC.

In the third quarter, net interest expense was $112 million, up from $2 million in the same quarter of 2001. In the nine months ended September 2002, net interest expense was $242 million compared with $21 million in the respective period of 2001. The rise in net interest expense resulted primarily from the additional interest expense associated with debt acquired as a result of the merger, an increase resulting from higher debt levels associated with the U.S. dollar notes issued in the fourth quarter of 2001 and lower 2002 cash levels.

Foreign exchange in the quarter resulted in a loss of $156 million, which compared with a loss of $17 million in the same quarter of 2001. The total gain resulting from foreign exchange in the nine months ended September 30, 2002 was $24 million, which compared to a loss of $14 million in the same period last year. The majority of the foreign exchange impact results from the translation of U.S. dollar denominated debt where exchange gains and losses are recorded in earnings in the period they arise.

In conjunction with the merger, in the second quarter, the Company reviewed its accounting for operations outside of Canada and determined that all such operations were self-sustaining. Previously all such operations had been considered to be integrated and as such were accounted for using the temporal method of translation. This change in classification resulted in a change to the current rate method of translation, which is used for self-sustaining operations and is described in Note 2 of the Consolidated Financial Statements. This change was adopted prospectively as of April 5, 2002 and resulted in a decrease in net earnings of $2 million in the third quarter of 2002 and $7 million in the year to date.

The third quarter provision for income tax was $142 million, down from $183 million in the same quarter of last year. In the year to date, the provision for income tax was $379 million, a decrease of $187 million from the same period in 2001. The decrease reflects the impact of lower year-to-date operating results combined with an approximately $42 million reduction to future income taxes resulting from a reduction in the Alberta corporate tax rate. The normalized effective tax rate for 2002 is expected to be 35 to 37 percent.

LIQUIDITY AND CAPITAL RESOURCES

Cash flow from continuing operations was $1,027 million in the third quarter and $2,330 million in the year to date, which compares to $562 million and $1,875 million in the respective periods of 2001. The increased cash flow from continuing operations was primarily the result of the merger of the Company with AEC.

The Company's net capital expenditures were $1,374 million in the quarter compared with $498 million in the same quarter of last year. Net expenditures in the quarter included approximately $539 million related to the acquisition of producing and non-producing properties in southwestern Wyoming. In the year to date, net capital expenditures were $3,058 million, an increase over $1,147 million in the same period of 2001. Year-to-date net expenditures include approximately $420 million related to the purchase of certain Colorado natural gas properties. The Company's net investing for the year to date was funded by cash flow of $2,349 million and long-term debt.

Excluding discontinued operations, EnCana's net debt, including preferred securities, increased to $8,561 million from $2,303 million at year-end 2001, primarily as a result of the merger with AEC. Net debt to capitalization, including all preferred securities as debt, was 39 percent, up slightly from 37 percent at December 31, 2001.

On October 2, 2002, the Company issued $300 million of unsecured five-year debentures at a coupon rate of 5.30 percent. Proceeds from the offering were used to repay amounts outstanding under revolving credit and term loan borrowings.

On October 16, 2002, EnCana received approval from the Toronto Stock Exchange ("TSX") to make a Normal Course Issuer Bid. Under the bid, EnCana may purchase for cancellation up to 23,843,565 of its Common Shares, representing five percent of the approximately 476,871,300 Common Shares outstanding as at October 4, 2002. Purchases may commence on October 22, 2002 and will terminate on October 21, 2003 or on such earlier date as the Company may complete its purchases pursuant to the Notice of Intention filed with the TSX. Purchases will be made on the open market through the facilities of the TSX in accordance with its policies. The price to be paid will be the market price at the time of acquisition.

RISK MANAGEMENT

Through the normal course of business, the Company is exposed to market risks associated with fluctuations in commodity prices, foreign exchange rates and interest rates in addition to credit and operational risks.

Exposure to market risks is managed by the Company through the use of various financial instruments and contracts. This risk management program is designed to enhance shareholder value by mitigating the volatility associated with commodity prices, exchange rates and interest rates, enhancing the probability of achieving corporate performance targets.

As a means of managing commodity price volatility, the Company has entered into various financial instrument agreements.

At September 30, 2002, the total unrecognized gain related to all significant natural gas contracts was $293 million, the details of which are outlined below.

Produced Gas

At September 30, 2002, all significant contracts related to produced gas had a total unrecognized gain of $246 million, the details of which are outlined below.

- Approximately 191 million cubic feet per day of natural gas was managed under derivative contracts at an average AECO equivalent of $5.83 per thousand cubic feet for the period to October 2002. The contracts had an unrecognized gain of $6 million at September 30, 2002.
- Approximately 45 million cubic feet per day of natural gas was sold at an average fixed NYMEX related price of US$4.16 per million British thermal units for the period to October 2002. The contracts had an unrecognized gain of $2 million at September 30, 2002.
- Approximately 415 million cubic feet per day of Rockies natural gas was sold forward and under derivative contracts for the period to October 2007 at a fixed differential of NYMEX less US$0.43 per million British thermal units. These contracts had an estimated unrecognized gain of $235 million at September 30, 2002.
- Approximately 60 million cubic feet per day of natural gas basis derivatives were sold for the period between January 2003 and December 2007 at an average NYMEX to AECO differential of US$0.43 per million British thermal units. These contracts had an unrecognized gain of $3 million at September 30, 2002.
- Approximately 114 million cubic feet per day of AECO natural gas call options were sold for the period to October 2002 at an average strike price of $6.05 per thousand cubic feet. There was no unrecognized gain or loss on the options at September 30, 2002.
- Approximately 327 million cubic feet per day of AECO natural gas collar options were entered into for the month of October 2002 with a floor price of $3.71 per thousand cubic feet and ceiling price of $5.50 per thousand cubic feet. There was no unrecognized gain or loss on the options at September 30, 2002.

Purchased Gas

- As part of the marketing business, the Company has entered into contracts to purchase and sell physical volumes of natural gas for the period to October 2003. Certain of these volumes were purchased at fixed prices and sold at index and subsequently fixed by financial swaps. These transactions are matched thereby creating a closed combined physical and financial position. On a combined basis these contracts had an unrecognized gain of $47 million at September 30, 2002.

Crude Oil

At September 30, 2002, all significant contracts related to crude oil had a total unrecognized loss of $32 million, the details of which are outlined below.

- For the remainder of 2002, there were approximately 50,000 barrels per day in costless collars with a price floor of US$22.00 per barrel and a price cap averaging US$27.72 per barrel. The unrecognized loss at September 30, 2002 was $20 million.
- For the remainder of 2002, there were approximately 35,000 barrels per day protected by put options with a strike price of US$20.00 per barrel. The unrecognized loss at September 30, 2002 was $3 million.
- For 2003, there were approximately 28,000 barrels per day in costless collars with a price floor averaging US$21.96 per barrel and a price cap of US$29.00 per barrel. The unrecognized loss at September 30, 2002 was $1 million.
- For 2003, there were approximately 40,000 barrels per day in fixed priced swaps with an average price of US$25.72 per barrel. The unrecognized loss at September 30, 2002 was $5 million.
- For 2004, there were approximately 33,000 barrels per day in costless collars with a price floor of US$20.00 per barrel and a price cap averaging US$25.76 per barrel. The unrecognized loss at September 30, 2002 was $1 million.
- For 2004, there were approximately 31,000 barrels per day in fixed priced swaps with an average price of US$23.08 per barrel. The unrecognized loss at September 30, 2002 was $2 million.

Storage Optimization

- Various financial instruments have been entered into for the next 13-month period to manage price volatility relating to the gas storage optimization program, including futures, fixed-for-floating swaps and basis swaps. At September 30, 2002, these instruments, on a combined basis, had a net unrecognized loss of $24 million, which was fully offset by unrealized gains on physical inventory in storage.

Power Purchase Arrangements

- As part of its cost management strategy during 2001 and 2000, the Company entered into two electricity contracts that expire in 2003 and 2005, respectively. At September 30, 2002, these contracts had an unrecognized loss of $13 million.

As a means of managing the exposure to fluctuations in the U.S. to Canadian exchange rate, the Company has entered into foreign exchange contracts in the amount of US$632 million at an average exchange rate of US$0.719 for the period to June 2004. The unrecognized loss with respect to these contracts was $132 million at September 30, 2002.

The Company has entered into various interest rate and cross currency interest rate swap transactions as a means of managing the interest rate exposure on debt instruments. The unrealized gain with respect to these transactions was $64 million at September 30, 2002.

The risk of credit losses is minimized through the use of mandated credit policies and procedures designed to limit exposures within acceptable levels. EnCana does not have a significant concentration of credit risk with any single counterparty and no significant bad debts have been incurred or provided for to date in 2002.

Operational risks are managed through a comprehensive insurance program designed to protect the Company from any significant losses arising from the risk exposures. Safety and environment risks are managed by executing policies and standards that comply with or exceed government regulations and industry standards. In addition, the Company maintains a system that identifies, assesses and controls safety and environmental risk and requires regular reporting to senior management and the Board of Directors.

OUTLOOK

The Company's sales for 2002 are forecast to be between 2,310 and 2,380 million cubic feet per day (2,715 to 2,785 million cubic feet per day full year pro forma) for produced natural gas and between 213,000 and 232,000 barrels per day (245,000 to 264,000 barrels per day full year pro forma) of oil and natural gas liquids. Volatility in world energy prices is expected to continue through the remainder of the year. The Company's risk management program is expected to assist in reducing the negative effect in the event of oil market price declines.

Capital investment in core programs is expected to be approximately $4.2 billion ($5.0 billion full year pro forma) before acquisitions and dispositions. It is expected that the Company will be able to fund this program largely from cash flow together with proceeds received on the disposition of non-core assets. Expenditures will continue to emphasize anticipated strong near-term production growth, particularly in natural gas, while exploration and development by Offshore and International focuses on medium and longer-term value creation.

November 4, 2002

EnCana Corporation

Consolidated Statement of Earnings

(unaudited) ($ millions, except per share amounts)		Three Months Ended September 30 2002	Three Months Ended September 30 2001	Nine Months Ended September 30 2002	Nine Months Ended September 30 2001
Revenues, Net of Royalties and Production Taxes	(note 4)	$ 2,882	$ 1,139	$ 6,619	$ 3,950
Expenses	(note 4)				
Transportation and selling		176	43	383	125
Operating		394	159	981	530
Purchased product		1,041	220	2,317	861
Administrative		50	36	111	77
Interest, net		112	2	242	21
Foreign exchange	(note 7)	156	17	(24)	14
Depreciation, depletion and amortization		616	202	1,410	591
		2,545	679	5,420	2,219
Net Earnings Before the Undernoted		337	460	1,199	1,731
Income tax expense	(note 6)	142	183	379	566
Distributions on Subsidiary Preferred Securities, net of tax		11	–	11	–
Net Earnings from Continuing Operations		184	277	809	1,165
Net Earnings from Discontinued Operations	(note 5)	20	(2)	(14)	32
Net Earnings		$ 204	$ 275	$ 795	$ 1,197
Net Earnings From Continuing Operations per common share	(note 9)				
Basic		$ 0.38	$ 1.07	$ 2.03	$ 4.54
Diluted		$ 0.38	$ 1.05	$ 1.99	$ 4.44
Net Earnings per common share	(note 9)				
Basic		$ 0.43	$ 1.07	$ 1.99	$ 4.67
Diluted		$ 0.42	$ 1.04	$ 1.96	$ 4.56

Consolidated Statement of Retained Earnings

(unaudited) ($ millions)		Nine Months Ended September 30 2002	Nine Months Ended September 30 2001
Retained Earnings, Beginning of Year			
As previously reported		$ 3,689	$ 3,721
Retroactive adjustment for change in accounting policy	(note 2)	(59)	(42)
As restated		3,630	3,679
Net Earnings		795	1,197
Dividends on Common Shares and Other Distributions, net of tax		(122)	(1,259)
Other Adjustments		–	(50)
Retained Earnings, End of Period		$ 4,303	$ 3,567

See accompanying notes to Consolidated Financial Statements.

EnCana Corporation

Consolidated Balance Sheet

(unaudited) ($ millions)		As at September 30, 2002	As at December 31, 2001
Assets			
Current Assets			
Cash and cash equivalents		**$ 430**	$ 963
Accounts receivable and accrued revenue		**1,819**	623
Inventories		**537**	87
		2,786	1,673
Capital Assets, net	*(note 4)*	**23,117**	8,162
Investments and Other Assets		**472**	237
Assets of Discontinued Operations	*(note 5)*	**1,336**	728
Goodwill	*(note 3)*	**3,077**	–
	(note 4)	**$ 30,788**	$ 10,800
Liabilities and Shareholders' Equity			
Current Liabilities			
Accounts payable and accrued liabilities		**$ 2,068**	$ 824
Income tax payable		**176**	656
Current portion of long-term debt	*(note 7)*	**213**	160
		2,457	1,640
Long-Term Debt	*(note 7)*	**8,306**	2,210
Deferred Credits and Other Liabilities		**563**	325
Future Income Taxes		**4,820**	2,060
Liabilities of Discontinued Operations	*(note 5)*	**842**	586
Preferred Securities of Subsidiary		**458**	–
		17,446	6,821
Shareholders' Equity			
Preferred securities		**126**	126
Share capital	*(note 8)*	**8,689**	196
Share options, net	*(note 3)*	**147**	–
Paid in surplus		**47**	27
Retained earnings		**4,303**	3,630
Foreign currency translation adjustment	*(note 2)*	**30**	–
		13,342	3,979
		$ 30,788	$ 10,800

See accompanying notes to Consolidated Financial Statements.

EnCana Corporation

Consolidated Statement of Cash Flows

(unaudited) ($ millions, except per share amounts)		Three Months Ended September 30 2002	Three Months Ended September 30 2001	Nine Months Ended September 30 2002	Nine Months Ended September 30 2001
Operating Activities					
Net earnings from continuing operations		**$ 184**	$ 277	**$ 809**	$ 1,165
Depreciation, depletion and amortization		**616**	202	**1,410**	591
Future income taxes	*(note 6)*	**130**	61	**271**	111
Other		**97**	22	**(160)**	8
Cash flow from continuing operations		**1,027**	562	**2,330**	1,875
Cash flow from discontinued operations	*(note 5)*	**(5)**	(2)	**19**	45
Cash flow		**1,022**	560	**2,349**	1,920
Net change in non-cash working capital from continuing operations		**(355)**	132	**(823)**	490
Net change in non-cash working capital from discontinued operations		**80**	(19)	**79**	(70)
		747	673	**1,605**	2,340
Investing Activities					
Business combination	*(note 3)*	**–**	–	**(128)**	–
Capital expenditures	*(note 4)*	**(1,507)**	(539)	**(3,434)**	(1,370)
Proceeds on disposal of assets		**133**	41	**376**	223
Net change in investments and other		**26**	(26)	**13**	(21)
Net change in non-cash working capital from continuing operations		**83**	45	**(167)**	(30)
Discontinued operations		**3**	1	**(9)**	10
		(1,262)	(478)	**(3,349)**	(1,188)
Financing Activities					
Issuance of short-term financing		**–**	440	**–**	440
Repayment of short-term financing		**–**	–	**–**	(250)
Issuance of long-term debt		**813**	150	**1,462**	244
Repayment of long-term debt		**–**	–	**(157)**	(249)
Issuance of common shares		**27**	8	**96**	41
Dividends on common shares		**(47)**	(1,205)	**(120)**	(1,256)
Payments to preferred securities holders		**(24)**	(2)	**(31)**	(6)
Net change in non-cash working capital		**3**	(3)	**2**	(2)
Discontinued operations		**(4)**	–	**(9)**	–
Other		**7**	–	**(25)**	–
		775	(612)	**1,218**	(1,038)
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency		**4**	6	**(7)**	15
Increase (Decrease) in Cash and Cash Equivalents		**264**	(411)	**(533)**	129
Cash and Cash Equivalents, Beginning of Period		**166**	737	**963**	197
Cash and Cash Equivalents, End of Period		**$ 430**	$ 326	**$ 430**	$ 326
Cash Flow per Common Share	*(note 9)*				
Basic		**$ 2.14**	$ 2.19	**$ 5.90**	$ 7.51
Diluted		**$ 2.12**	$ 2.13	**$ 5.80**	$ 7.34

See accompanying notes to Consolidated Financial Statements.

EnCana Corporation

Notes to Consolidated Financial Statements *(Unaudited)*

1. BASIS OF PRESENTATION

The interim consolidated financial statements include the accounts of EnCana Corporation (formerly PanCanadian Energy Corporation) ("PanCanadian") and its subsidiaries (the "Company"), including Alberta Energy Company Ltd. (see Note 3), and are presented in accordance with Canadian generally accepted accounting principles. The Company is in the business of exploration, production and marketing of natural gas and crude oil, as well as pipelines, natural gas liquids processing and gas storage operations.

The interim consolidated financial statements have been prepared following the same accounting policies and methods of computation as the annual audited consolidated financial statements for the year ended December 31, 2001, except as described in Note 2. The disclosures provided below are incremental to those included with the annual audited consolidated financial statements. The interim consolidated financial statements should be read in conjunction with the annual audited consolidated financial statements and the notes thereto for the year ended December 31, 2001.

2. CHANGES IN ACCOUNTING POLICIES

Foreign Currency Translation

At January 1, 2002, the Company retroactively adopted amendments to the Canadian accounting standard for foreign currency translation. As a result of the amendments, all exchange gains and losses on long-term monetary items, that do not qualify for hedge accounting, are recorded in earnings as they arise. Specifically, the Company is now required to translate long-term debt denominated in U.S. dollars into Canadian dollars at the period-end exchange rate with any resulting adjustment recorded in the Consolidated Statement of Earnings. Previously, these exchange gains and losses were deferred and amortized over the remaining life of the monetary item.

As required by the standard, all prior periods have been restated for the change in accounting policy. The change results in a decrease in net earnings of $65 million for the three months ended September 30, 2002 (2001 – $14 million) and an increase in net earnings of $16 million for the nine months ended September 30, 2002 (2001 – decrease of $16 million). The effect of this change on the December 31, 2001 consolidated balance sheet is an increase in long-term debt and a reduction in deferred credits of $92 million, as well as a reduction in deferred charges and retained earnings of $59 million.

In conjunction with the business combination described in Note 3, the Company reviewed its accounting for operations outside of Canada and determined that all such operations are self-sustaining. The accounts of self-sustaining foreign subsidiaries are translated using the current rate method, whereby assets and liabilities are translated at period-end exchange rates, while revenues and expenses are translated using average rates for the period. Translation gains and losses relating to the subsidiaries are deferred and included as a separate component of shareholders' equity. Previously, operations outside of Canada were considered to be integrated and translated using the temporal method. Under the temporal method, monetary assets and liabilities were translated at the period-end exchange rate, other assets and liabilities at the historical rates and revenues and expenses at the average monthly rates except depreciation and depletion, which were translated on the same basis as the related assets.

This change was adopted prospectively beginning April 5, 2002, and results in a decrease in net earnings of $2 million for the three months ended September 30, 2002 and a decrease of $7 million for the nine months ended September 30, 2002.

Accounting for Marketing Operations

As a result of the substantial completion in the third quarter of the wind-down of the Houston-based merchant energy operations, the Company reviewed its accounting for the continuing marketing operations and determined that such operations will not follow mark-to-market accounting. This change to accounting for continuing marketing operations was adopted prospectively at the end of the third quarter.

3. BUSINESS COMBINATION

On January 27, 2002, PanCanadian and Alberta Energy Company Ltd. ("AEC") announced plans to combine their companies. The transaction was accomplished through a plan of arrangement (the "Arrangement") under the *Business Corporations Act* (Alberta). The Arrangement included a common share exchange, pursuant to which holders of common shares of AEC received 1.472 common shares of PanCanadian for each common share of AEC that they held. After obtaining approvals of the common shareholders and optionholders of AEC and the common shareholders of PanCanadian, the Court of Queen's Bench of Alberta and appropriate regulatory and other authorities, the transaction closed April 5, 2002, and PanCanadian changed its name to EnCana Corporation ("EnCana").

EnCana Corporation

Notes to Consolidated Financial Statements *(Unaudited)*

3. BUSINESS COMBINATION (continued)

This business combination has been accounted for using the purchase method with the results of operations of AEC included in the consolidated financial statements from the date of acquisition. The Arrangement resulted in PanCanadian issuing 218.5 million Common Shares and a transaction value of $8,714 million. The calculation of the purchase price and the preliminary allocation to assets and liabilities acquired as of April 5, 2002 is shown below. The purchase price and goodwill allocation is preliminary because certain items such as the determination of the final tax bases and fair values of the assets and liabilities as of the acquisition date have not been completed. Further information related to AEC can be obtained from the audited consolidated financial statements included in the Joint Information Circular concerning the merger of AEC and PanCanadian.

		($ millions)
Calculation of Purchase Price:		
Common Shares issued to AEC shareholders *(millions)*	218.5	
Price of Common Shares *($ per common share)*	38.43	
Value of Common Shares issued		$ 8,397
Fair value of AEC share options exchanged for share options of EnCana Corporation ("Share options")		167
Transaction costs		150
Total purchase price		8,714
Plus: Fair value of liabilities assumed		
Current liabilities		1,781
Long-term debt, including Capital Securities		4,843
Project financing debt		604
Preferred securities		458
Other non-current liabilities		193
Future income taxes		2,647
Total Purchase Price and Liabilities Assumed		$ 19,240

	($ millions)
Fair Value of Assets Acquired:	
Current assets	$ 1,505
Capital assets	14,053
Other non-current assets	605
Goodwill	3,077
Total Fair Value of Assets Acquired	$ 19,240

4. SEGMENTED INFORMATION

Due to the business combination as described in Note 3, the Company has redefined its operations into the following segments. Onshore North America includes the Company's North America onshore exploration for, and production of, natural gas and crude oil. Offshore and International combines the Offshore and International Operations Division's exploration for, and production of, crude oil and natural gas in Ecuador, the Canadian East Coast, the Gulf of Mexico and the U.K. North Sea with the Offshore and New Ventures Exploration Division's exploration activity in the Canadian East Coast, the North America frontier region, the Gulf of Mexico, the U.K. North Sea, the Middle East, Africa, Australia and Latin America. Midstream and Marketing includes natural gas liquids processing and gas storage operations as well as marketing activity under which the Company purchases and takes delivery of product from others and delivers product to customers under transportation arrangements not utilized for the Company's own production. All prior periods have been restated to conform to these definitions. Operations that have been discontinued are disclosed in Note 5.

EnCana Corporation

Notes to Consolidated Financial Statements *(Unaudited)*

4. SEGMENTED INFORMATION (continued)

Results of Operations (For the Three Months Ended September 30)

	Onshore North America		Offshore and International		Midstream and Marketing	
($ millions)	**2002**	2001	**2002**	2001	**2002**	2001
Revenues						
Gross revenue	**$ 1,725**	$ 863	**$ 223**	$ 43	**$ 1,188**	$ 291
Royalties and production taxes	**194**	62	**64**	–	**–**	–
Revenues, net of royalties and production taxes	**1,531**	801	**159**	43	**1,188**	291
Expenses						
Transportation and selling	**109**	35	**19**	5	**48**	3
Operating	**276**	109	**43**	4	**75**	46
Purchased product	**–**	–	**–**	–	**1,041**	220
Depreciation, depletion and amortization	**516**	176	**68**	19	**14**	3
Segment Income	**$ 630**	$ 481	**$ 29**	$ 15	**$ 10**	$ 19

	Corporate		Consolidated	
	2002	2001	**2002**	2001
Revenues				
Gross revenue	**$ 4**	$ 4	**$ 3,140**	$ 1,201
Royalties and production taxes	**–**	–	**258**	62
Revenues, net of royalties and production taxes	**4**	4	**2,882**	1,139
Expenses				
Transportation and selling	**–**	–	**176**	43
Operating	**–**	–	**394**	159
Purchased product	**–**	–	**1,041**	220
Depreciation, depletion and amortization	**18**	4	**616**	202
Segment Income	**(14)**	–	**655**	515
Administrative	**50**	36	**50**	36
Interest, net	**112**	2	**112**	2
Foreign exchange	**156**	17	**156**	17
	318	55	**318**	55
Net Earnings Before Income Tax	**(332)**	(55)	**337**	460
Income tax expense	**142**	183	**142**	183
Distribution on Subsidiary Preferred Securities, net of tax	**11**	–	**11**	–
Net Earnings from Continuing Operations	**$ (485)**	$ (238)	**$ 184**	$ 277

EnCana Corporation

Notes to Consolidated Financial Statements *(Unaudited)*

4. SEGMENTED INFORMATION (continued)

Geographic and Product Information (For the Three Months Ended September 30)

ONSHORE NORTH AMERICA

	Produced Gas and NGLs			
	Canada		U.S. Rockies	
	2002	2001	**2002**	2001
Revenues				
Gross revenue	**$ 883**	$ 561	**$ 260**	$ 31
Royalties and production taxes	**83**	22	**55**	7
Revenues, net of royalties and production taxes	**800**	539	**205**	24
Expenses				
Transportation and selling	**58**	28	**32**	–
Operating	**123**	46	**18**	6
Operating Cash Flow	**$ 619**	$ 465	**$ 155**	$ 18

	Conventional Crude Oil		Syncrude		Total Onshore North America	
	2002	2001	**2002**	2001	**2002**	2001
Revenues						
Gross revenue	**$ 439**	$ 271	**$ 143**	$ –	**$ 1,725**	$ 863
Royalties and production taxes	**54**	33	**2**	–	**194**	62
Revenues, net of royalties and production taxes	**385**	238	**141**	–	**1,531**	801
Expenses						
Transportation and selling	**17**	7	**2**	–	**109**	35
Operating	**91**	57	**44**	–	**276**	109
Operating Cash Flow	**$ 277**	$ 174	**$ 95**	$ –	**$ 1,146**	$ 657

OFFSHORE AND INTERNATIONAL

	Ecuador		U.K. North Sea		Other Countries		Total Offshore and International	
	2002	2001	**2002**	2001	**2002**	2001	**2002**	2001
Revenues								
Gross revenue	**$ 186**	$ –	**$ 37**	$ 43	**$ –**	$ –	**$ 223**	$ 43
Royalties and production taxes	**64**	–	**–**	–	**–**	–	**64**	–
Revenues, net of royalties and production taxes	**122**	–	**37**	43	**–**	–	**159**	43
Expenses								
Transportation and selling	**14**	–	**5**	5	**–**	–	**19**	5
Operating	**24**	–	**5**	4	**14**	–	**43**	4
Operating Cash Flow	**$ 84**	$ –	**$ 27**	$ 34	**$ (14)**	$ –	**$ 97**	$ 34

MIDSTREAM AND MARKETING

	Midstream		Marketing		Total Midstream and Marketing	
	2002	2001	**2002**	2001	**2002**	2001
Revenues						
Gross revenue	**$ 179**	$ 51	**$ 1,009**	$ 240	**$ 1,188**	$ 291
Expenses						
Transportation and selling	**–**	–	**48**	3	**48**	3
Operating	**69**	43	**6**	3	**75**	46
Purchased product	**72**	–	**969**	220	**1,041**	220
Operating Cash Flow	**$ 38**	$ 8	**$ (14)**	$ 14	**$ 24**	$ 22

EnCana Corporation

Notes to Consolidated Financial Statements *(Unaudited)*

4. SEGMENTED INFORMATION (continued)

Results of Operations (For the Nine Months Ended September 30)

	Onshore North America		Offshore and International		Midstream and Marketing	
($ millions)	**2002**	2001	**2002**	2001	**2002**	2001
Revenues						
Gross revenue	**$ 3,942**	$ 2,906	**$ 494**	$ 130	**$ 2,788**	$ 1,137
Royalties and production taxes	**485**	244	**123**	–	**–**	–
Revenues, net of royalties and production taxes	**3,457**	2,662	**371**	130	**2,788**	1,137
Expenses						
Transportation and selling	**241**	99	**39**	14	**103**	12
Operating	**651**	319	**92**	11	**238**	200
Purchased product	**–**	–	**–**	–	**2,317**	861
Depreciation, depletion and amortization	**1,187**	506	**142**	52	**45**	10
Segment Income	**$ 1,378**	$ 1,738	**$ 98**	$ 53	**$ 85**	$ 54

	Corporate		Consolidated	
	2002	2001	**2002**	2001
Revenues				
Gross revenue	**$ 3**	$ 21	**$ 7,227**	$ 4,194
Royalties and production taxes	**–**	–	**608**	244
Revenues, net of royalties and production taxes	**3**	21	**6,619**	3,950
Expenses				
Transportation and selling	**–**	–	**383**	125
Operating	**–**	–	**981**	530
Purchased product	**–**	–	**2,317**	861
Depreciation, depletion and amortization	**36**	23	**1,410**	591
Segment Income	**(33)**	(2)	**1,528**	1,843
Administrative	**111**	77	**111**	77
Interest, net	**242**	21	**242**	21
Foreign exchange	**(24)**	14	**(24)**	14
	329	112	**329**	112
Net Earnings Before Income Tax	**(362)**	(114)	**1,199**	1,731
Income tax expense	**379**	566	**379**	566
Distributions on Subsidiary Preferred Securities, net of tax	**11**	–	**11**	–
Net Earnings from Continuing Operations	**$ (752)**	$ (680)	**$ 809**	$ 1,165

EnCana Corporation

Notes to Consolidated Financial Statements *(Unaudited)*

4. SEGMENTED INFORMATION (continued)

Geographic and Product Information (For the Nine Months Ended September 30)

ONSHORE NORTH AMERICA

	Produced Gas and NGLs			
	Canada		U.S. Rockies	
	2002	2001	**2002**	2001
Revenues				
Gross revenue	**$ 2,199**	$ 2,100	**$ 467**	$ 94
Royalties and production taxes	**243**	116	**104**	32
Revenues, net of royalties and production taxes	**1,956**	1,984	**363**	62
Expenses				
Transportation and selling	**146**	79	**57**	–
Operating	**274**	126	**38**	12
Operating Cash Flow	**$ 1,536**	$ 1,779	**$ 268**	$ 50

	Conventional Crude Oil		Syncrude		Total Onshore North America	
	2002	2001	**2002**	2001	**2002**	2001
Revenues						
Gross revenue	**$ 1,042**	$ 712	**$ 234**	$ –	**$ 3,942**	$ 2,906
Royalties and production taxes	**135**	96	**3**	–	**485**	244
Revenues, net of royalties and production taxes	**907**	616	**231**	–	**3,457**	2,662
Expenses						
Transportation and selling	**35**	20	**3**	–	**241**	99
Operating	**227**	181	**112**	–	**651**	319
Operating Cash Flow	**$ 645**	$ 415	**$ 116**	$ –	**$ 2,565**	$ 2,244

OFFSHORE AND INTERNATIONAL

	Ecuador		U.K. North Sea		Other Countries		Total Offshore and International	
	2002	2001	**2002**	2001	**2002**	2001	**2002**	2001
Revenues								
Gross revenue	**$ 368**	$ –	**$ 126**	$ 130	**$ –**	$ –	**$ 494**	$ 130
Royalties and production taxes	**123**	–	**–**	–	**–**	–	**123**	–
Revenues, net of royalties and production taxes	**245**	–	**126**	130	**–**	–	**371**	130
Expenses								
Transportation and selling	**24**	–	**15**	14	**–**	–	**39**	14
Operating	**55**	–	**11**	11	**26**	–	**92**	11
Operating Cash Flow	**$ 166**	$ –	**$ 100**	$ 105	**$ (26)**	$ –	**$ 240**	$ 105

MIDSTREAM AND MARKETING

	Midstream		Marketing		Total Midstream and Marketing	
	2002	2001	**2002**	2001	**2002**	2001
Revenues						
Gross revenue	**$ 439**	$ 221	**$ 2,349**	$ 916	**$ 2,788**	$ 1,137
Expenses						
Transportation and selling	**–**	–	**103**	12	**103**	12
Operating	**226**	188	**12**	12	**238**	200
Purchased product	**123**	–	**2,194**	861	**2,317**	861
Operating Cash Flow	**$ 90**	$ 33	**$ 40**	$ 31	**$ 130**	$ 64

EnCana Corporation

Notes to Consolidated Financial Statements *(Unaudited)*

4. SEGMENTED INFORMATION (continued)

Capital Expenditures

	Three Months Ended September 30		Nine Months Ended September 30	
	2002	2001	**2002**	2001
Onshore North America	**$ 1,168**	$ 372	**$ 2,552**	$ 978
Offshore and International	**294**	129	**703**	265
Midstream and Marketing	**24**	36	**148**	105
Corporate	**21**	2	**31**	22
Total	**$ 1,507**	$ 539	**$ 3,434**	$ 1,370

Capital and Total Assets

	As at			
	Capital Assets		Total Assets	
	September 30, 2002	December 31, 2001	**September 30, 2002**	December 31, 2001
Onshore North America	**$ 18,724**	$ 6,552	**$ 20,094**	$ 7,080
Offshore and International	**3,182**	1,018	**3,490**	1,111
Midstream and Marketing	**998**	426	**2,127**	817
Corporate (including unallocated Goodwill)	**213**	166	**3,701**	1,064
Assets of Discontinued Operations	**–**	–	**1,376**	728
Total	**$ 23,117**	$ 8,162	**$ 30,788**	$ 10,800

5. DISCONTINUED OPERATIONS

On April 24, 2002, the Company adopted formal plans to exit from the Houston-based merchant energy operation, which was included in the Midstream and Marketing segment. Accordingly, these operations have been accounted for as discontinued operations.

On July 9, 2002, the Company announced that it plans to sell its 70 percent equity investment in the Cold Lake Pipeline System and its 100 percent interest in the Express Pipeline System. Both crude oil pipeline systems were acquired in the business combination with Alberta Energy Company Ltd. on April 5, 2002 described in Note 3. Accordingly, these operations have been accounted for as discontinued operations. The Company, through indirect wholly owned subsidiaries, is a shipper on the Express system and the Cold Lake pipeline. The financial results for the nine months ended September 30, 2002 shown below includes tariff revenue of $42 million paid by the Company for services on Express (three months ended – $19 million).

CONSOLIDATED STATEMENT OF EARNINGS

	For the Three Months Ended September 30					
	Merchant Energy		Midstream – Pipelines		Total	
($ millions)	**2002**	2001	**2002**	2001	**2002**	2001
Revenues	**$ 154**	$ 782	**$ 91**	$ –	**$ 245**	$ 782
Expenses						
Operating	**–**	–	**33**	–	**33**	–
Purchased product	**162**	758	**–**	–	**162**	758
Administrative	**16**	25	**–**	–	**16**	25
Interest, net	**–**	–	**11**	–	**11**	–
Foreign exchange	**–**	–	**7**	–	**7**	–
Depreciation, depletion and amortization	**–**	1	**12**	–	**12**	1
Gain on discontinuance	**(29)**	–	**–**	–	**(29)**	–
	149	784	**63**	–	**212**	784
Net Earnings (Loss) Before Income Tax	**5**	(2)	**28**	–	**33**	(2)
Income tax expense	**2**	–	**11**	–	**13**	–
Net Earnings (Loss) from Discontinued Operations	**$ 3**	$ (2)	**$ 17**	$ –	**$ 20**	$ (2)

EnCana Corporation

Notes to Consolidated Financial Statements *(Unaudited)*

5. DISCONTINUED OPERATIONS (continued)

CONSOLIDATED STATEMENT OF EARNINGS

	For the Nine Months Ended September 30					
	Merchant Energy		Midstream – Pipelines*		Total	
($ millions)	**2002**	2001	**2002**	2001	**2002**	2001
Revenues	**$ 1,463**	$ 3,349	**$ 149**	$ –	**$ 1,612**	$ 3,349
Expenses						
Operating	**–**	–	**53**	–	**53**	–
Purchased product	**1,475**	3,253	**–**	–	**1,475**	3,253
Administrative	**34**	40	**–**	–	**34**	40
Interest, net	**–**	–	**22**	–	**22**	–
Foreign exchange	**–**	–	**(3)**	–	**(3)**	–
Depreciation, depletion and amortization	**1**	3	**23**	–	**24**	3
Loss on discontinuance	**24**	–	**–**	–	**24**	–
	1,534	3,296	**95**	–	**1,629**	3,296
Net Earnings (Loss) Before Income Tax	**(71)**	53	**54**	–	**(17)**	53
Income tax expense (recovery)	**(25)**	21	**22**	–	**(3)**	21
Net Earnings (Loss) from Discontinued Operations	**$ (46)**	$ 32	**$ 32**	$ –	**$ (14)**	$ 32

* Reflects only six months of earnings as EnCana did not own the pipelines until April 5, 2002.

CONSOLIDATED BALANCE SHEET

	As at September 30					
	Merchant Energy		Midstream – Pipelines		Total	
($ millions)	**2002**	2001	**2002**	2001	**2002**	2001
Assets						
Cash and cash equivalents	**$ –**	$ –	**$ 60**	$ –	**$ 60**	$ –
Accounts receivable and accrued revenue	**55**	1,377	**32**	–	**87**	1,377
Inventories	**–**	33	**1**	–	**1**	33
	55	1,410	**93**	–	**148**	1,410
Capital assets, net	**–**	8	**819**	–	**819**	8
Investments and other assets	**–**	17	**369**	–	**369**	17
	55	1,435	**1,281**	–	**1,336**	1,435
Liabilities						
Accounts payable and accrued liabilities	**30**	1,269	**44**	–	**74**	1,269
Income tax payable	**–**	–	**5**	–	**5**	–
Current portion of long-term debt	**–**	–	**25**	–	**25**	–
	30	1,269	**74**	–	**104**	1,269
Long-term debt	**–**	–	**583**	–	**583**	–
Deferred credits and other liabilities	**–**	2	**–**	–	**–**	2
Future income taxes	**–**	–	**155**	–	**155**	–
	30	1,271	**812**	–	**842**	1,271
Net Assets of Discontinued Operations	**$ 25**	$ 164	**$ 469**	$ –	**$ 494**	$ 164

EnCana Corporation

Notes to Consolidated Financial Statements *(Unaudited)*

5. DISCONTINUED OPERATIONS (continued)

For comparative purposes, the following tables present the effect of only the Merchant Energy Discontinued Operations on the Consolidated Financial Statements for the years ended December 31. It does not include any financial information related to Midstream – Pipelines as EnCana did not own the pipelines being discontinued at that time.

CONSOLIDATED STATEMENT OF EARNINGS

($ millions)	Year Ended December 31 2001	2000
Revenues	**$ 4,085***	$ 3,025
Expenses		
Purchased product	**3,983***	2,961
Administrative	**43**	26
Depreciation, depletion and amortization	**4**	3
	4,030	2,990
Net Earnings Before Income Tax	**55**	35
Income tax expense	**22**	13
Net Earnings from Discontinued Operations	**$ 33**	$ 22

* Upon review of additional information related to 2001 sales and purchases of natural gas by the U.S. marketing subsidiary, the Company has determined certain revenue and expenses should have been reflected in the financial statements on a net basis rather than included on a gross basis as Revenue and Expenses – Purchased product. The amendment had no effect on net earnings or cash flow but Revenues and Expenses – Purchased product have been reduced by $1,126 million.

CONSOLIDATED BALANCE SHEET

($ millions)	As at December 31 2001	2000
Assets		
Accounts receivable and accrued revenue	**$ 323**	$ 699
Risk management assets	**309**	–
Inventories	**70**	2
	702	701
Capital assets, net	**9**	3
Deferred charges and other assets	**17**	32
	728	736
Liabilities		
Accounts payable and accrued liabilities	**306**	631
Risk management liabilities	**278**	–
	584	631
Deferred credits and liabilities	**2**	3
	586	634
Net Assets of Discontinued Operations	**$ 142**	$ 102

CONSOLIDATED STATEMENT OF CASH FLOWS

($ millions)	Year Ended December 31 2001	2000
Operating Activities		
Cash flow	**$ 47**	$ 26
Net change in non-cash working capital	**(48)**	(2)
	$ (1)	$ 24

EnCana Corporation

Notes to Consolidated Financial Statements *(Unaudited)*

6. INCOME TAXES

($ millions)	Three Months Ended September 30 **2002**	2001	Nine Months Ended September 30 **2002**	2001
Provision for Income Taxes:				
Current				
Canada	**$ 56**	$ 119	**$ 129**	$ 454
United States	**(57)**	–	**(49)**	(7)
Ecuador	**7**	–	**14**	–
United Kingdom	**4**	2	**12**	7
Other	**2**	1	**2**	1
	12	122	**108**	455
Future	**130**	61	**271**	111
	$ 142	$ 183	**$ 379**	$ 566

7. LONG-TERM DEBT

($ millions)	As at **September 30, 2002**	December 31, 2001
Canadian dollar denominated debt		
Revolving credit and term loan borrowings	**$ 1,752**	$ 37
Unsecured debentures, including Capital Securities	**1,955**	725
	3,707	762
U.S. dollar denominated debt		
U.S. unsecured senior notes	**3,936**	1,608
U.S. revolving credit and term loan borrowings	**751**	–
	4,687	1,608
	8,394	2,370
Increase in value of debt acquired	**125**	–
Current portion of long-term debt	**(213)**	(160)
	$ 8,306	$ 2,210

Certain of the notes and debentures of the Company were acquired in the business combination described in Note 3 and are accounted for at their fair value. The difference between the fair value and the principal amount of the debt acquired is being amortized over the remaining life of the outstanding debt acquired, approximately 15 years.

As required by Canadian generally accepted accounting principles, the Company's U.S. dollar denominated debt is translated into Canadian dollars at the period-end exchange rate. Translation gains and losses are recorded in income. Included in the $24 million foreign exchange gain for the nine months ended September 30, 2002, the Company recorded a foreign exchange gain of $21 million ($17 million after tax) related to the translation of U.S. dollar debt. Included in the $156 million foreign exchange loss for the three months ended September 30, 2002, the Company recorded a foreign exchange loss of $183 million ($145 million after tax) related to the translation of U.S. dollar debt.

On October 2, 2002, the Company issued $300 million of unsecured debentures at a coupon rate of 5.30 percent. Proceeds from the offering were used to repay amounts outstanding under revolving credit and term loan borrowings.

On October 16, 2002, the Company announced that it had established October 22, 2002 as the record date for a meeting of Capital Securities holders to consider, and if thought advisable to approve, amendments to the terms of such Capital Securities to provide the Company with the right to call for the early redemption of the Capital Securities, with a face value of $430 million.

EnCana Corporation

Notes to Consolidated Financial Statements *(Unaudited)*

8. SHARE CAPITAL

(millions)		September 30, 2002 Number	September 30, 2002 Amount	December 31, 2001 Number	December 31, 2001 Amount
Common Shares outstanding, beginning of period		**254.9**	**$ 196**	254.8	$ 148
Shares repurchased		**–**	**–**	(0.2)	–
Shares issued under option plans		**4.0**	**96**	1.9	48
Shares issued to AEC Shareholders	*(note 3)*	**218.5**	**8,397**	–	–
Adjustments due to Canadian Pacific Limited reorganization		**–**	**–**	(1.6)	–
Common Shares outstanding, end of period		**477.4**	**$ 8,689**	254.9	$ 196

The Company has a stock-based compensation plan ("EnCana plan") that allows employees to purchase Common Shares of the Company. Option exercise prices approximate the market price for the Common Shares on the date the options were issued. Options granted under the plan are generally fully exercisable after three years and expire five years after the grant date. Options granted under previous EnCana and Canadian Pacific Limited replacement plans expire 10 years from the date the options were granted.

In conjunction with the business combination transaction described in Note 3, options to purchase AEC common shares were replaced with options to purchase Common Shares of EnCana ("AEC replacement plan"). The transaction also resulted in these replacement options along with all options outstanding under the EnCana plan, becoming exercisable after the close of business on April 5, 2002.

The following tables summarize the information about options to purchase Common Shares at September 30, 2002:

	Share Options *(millions)*	Weighted Average Exercise Price *($)*
Outstanding, beginning of period	**10.5**	**32.31**
Granted under EnCana plan	**11.7**	**48.23**
Granted under AEC replacement plan	**13.1**	**32.01**
Granted under Directors' plan	**0.1**	**48.04**
Exercised	**(4.0)**	**24.10**
Forfeited	**(0.2)**	**36.87**
Outstanding, end of period	**31.2**	**39.16**
Exercisable, end of period	**19.4**	**33.69**

Range of Exercise Price *($)*	Outstanding Options: Number of Options Outstanding *(millions)*	Outstanding Options: Weighted Average Remaining Contractual Life *(years)*	Outstanding Options: Weighted Average Exercise Price *($)*	Exercisable Options: Number of Options Outstanding *(millions)*	Exercisable Options: Weighted Average Exercise Price *($)*
13.50 to 19.99	4.0	1.4	18.62	4.0	18.62
20.00 to 24.99	2.4	2.6	22.24	2.4	22.24
25.00 to 29.99	3.4	2.6	26.58	3.4	26.58
30.00 to 43.99	2.1	3.3	38.09	2.0	38.01
44.00 to 53.00	19.3	4.1	47.92	7.6	47.40
	31.2	3.1	39.16	19.4	33.69

Notes to Consolidated Financial Statements *(Unaudited)*

8. SHARE CAPITAL (continued)

The Company does not record compensation expense in the financial statements for share options granted to employees and directors because there is no intrinsic value at the date of grant. If the fair-value method had been used, the Company's net earnings and net earnings per share would approximate the following pro forma amounts:

($ millions, except per share amounts)	Nine Months Ended September 30 **2002**	Nine Months Ended September 30 2001
Compensation Costs	**$ 65**	$ 18
Net Earnings		
As reported	**795**	1,197
Pro forma	**730**	1,179
Net Earnings per Common Share		
Basic		
As reported	**1.99**	4.67
Pro forma	**1.83**	4.60
Diluted		
As reported	**1.96**	4.56
Pro forma	**1.80**	4.49

As described above, the acquisition of AEC resulted in all outstanding options at April 5, 2002 becoming fully exercisable. As the stock option expense is normally recognized over the expected life, the early vesting of outstanding options resulted in an acceleration of the compensation cost. As such, a $33 million expense relating to options outstanding at April 5, 2002 was included in the 2002 pro forma earnings above.

The fair value of each option granted is estimated on the date of grant using the Black-Scholes option-pricing model with weighted average assumptions for grants as follows:

	Nine Months Ended September 30 **2002**	Nine Months Ended September 30 2001
Risk-free interest rate	**4.36%**	4.24%
Expected lives *(years)*	**3.00**	3.00
Expected volatility	**0.35**	0.35
Annual dividend per share	**$ 0.40**	$ 0.40

9. PER SHARE AMOUNTS

The following table summarizes the Common Shares used in calculating net earnings and cash flow per Common Share.

	Three Months Ended				Nine Months Ended	
	March 31	June 30	September 30		September 30	
(millions)	**2002**	**2002**	**2002**	2001	**2002**	2001
Weighted average Common Shares outstanding – basic	255.3	461.1	**476.8**	256.2	**397.8**	255.8
Effect of dilutive securities	5.7	8.9	**5.4**	5.6	**6.9**	5.9
Weighted average Common Shares outstanding – diluted	261.0	470.0	**482.2**	261.8	**404.7**	261.7

The net earnings per common share calculations include the effect of the Distributions on Preferred Securities, net of tax for the three months of $1 million (2001 – $1 million) and for the year to date of $2 million (2001 – $3 million).

EnCana Corporation

Notes to Consolidated Financial Statements *(Unaudited)*

10. RISK MANAGEMENT

Unrecognized gains (losses) on risk management activities:

($ millions)	September 30, 2002
Natural gas	$ 293
Crude oil	(32)
Gas storage	(24)
Electricity	(13)
Foreign currency	(132)
Interest rates	64
Preferred securities	5
	$ 161

Information, with respect to contracts in place at December 31, 2001, is disclosed in Note 17 to the PanCanadian annual audited consolidated financial statements and Note 15 to the AEC annual audited consolidated financial statements.

11. RECLASSIFICATION

Certain information provided for prior periods has been reclassified to conform to the presentation adopted in 2002.

Supplemental Financial Information *(Unaudited)*

For the Three Months Ended September 30, 2002

FINANCIAL STATISTICS

(C$ millions, except per share amounts)	2002 Q3	2002 Q2
Earnings excluding foreign exchange on translation of U.S. dollar long-term debt (after tax) *	**349**	295
Per share – Diluted	**0.72**	0.63
Net Earnings from Continuing Operations	**184**	494
Per share – Basic	**0.38**	1.07
– Diluted	**0.38**	1.05
Net Earnings	**204**	458
Per share – Basic	**0.43**	0.99
– Diluted	**0.42**	0.97
Cash Flow from Continuing Operations	**1,027**	916
Per share – Basic	**2.15**	1.99
– Diluted	**2.13**	1.95
Cash Flow	**1,022**	938
Per share – Basic	**2.14**	2.03
– Diluted	**2.12**	2.00
Shares		
Common Shares outstanding *(millions)*		
Average	**476.8**	461.1
Average diluted	**482.2**	470.0
Price range *($ per share)*		
TSX – C$		
High	**48.25**	50.25
Low	**38.05**	43.62
Close	**48.00**	46.70
NYSE – US$		
High	**31.35**	32.20
Low	**24.08**	28.50
Close	**30.10**	30.60
Share volume traded *(millions)*	**105.5**	113.2
Share value traded *($ millions weekly average)*	**366.3**	412.6
Ratios		
Debt to Capitalization	**39%**	39%

* The Company is required to translate long-term debt denominated in U.S. dollars into Canadian dollars at the period-end exchange rate with any resulting adjustment recorded in the Consolidated Statement of Earnings.

Supplemental Oil and Gas Operating Statistics *(Unaudited)*

For the Three Months Ended September 30, 2002

OPERATING STATISTICS

SALES VOLUMES	2002 Q3	2002 Q2
Produced Gas *(MMcf/d)*		
Canada	**2,129**	2,144
United States	**550**	428
United Kingdom	**9**	8
	2,688	2,580
Oil and Natural Gas Liquids *(bbls/d)*		
Onshore North America		
Conventional Light and Medium Oil	**65,345**	66,807
Conventional Heavy Oil	**80,797**	76,233
Natural Gas Liquids		
Canada	**16,225**	16,796
United States	**6,702**	7,115
Total Onshore North America Conventional	**169,069**	166,951
Syncrude	**36,039**	24,295
Total Onshore North America	**205,108**	191,246
Offshore and International		
Ecuador	**55,579**	59,864
United Kingdom	**9,538**	11,966
Total Offshore and International	**65,117**	71,830
	270,225	263,076
Total *(boe/d)*	**718,225**	693,104

PER-UNIT RESULTS

	Q3	Q2
Produced Gas – Canada *($/Mcf)**		
Price, net of transportation and selling**	**3.53**	4.11
Royalties	**0.39**	0.65
Operating expenses	**0.58**	0.54
Netback including hedge	**2.56**	2.92
Hedge	**0.29**	(0.12)
Netback excluding hedge	**2.27**	3.04
Produced Gas – United States *(C$/Mcf)**		
Price, net of transportation and selling**	**3.73**	3.62
Royalties	**0.99**	0.98
Operating expenses	**0.34**	0.38
Netback including hedge	**2.40**	2.26
Hedge	**0.57**	0.06
Netback excluding hedge	**1.83**	2.20

* Excludes the effect of $168 million ($91 million in Q3; $77 million in Q2) increase to consolidated revenues relating to the mark-to-market value of the AEC fixed price forward natural gas contracts recorded as part of the purchase price allocation as there is no cash flow impact.

** Operating Netbacks for each product include the margin impact of marketing activities related to the purchase and sale of third-party volumes of the similar products.

Supplemental Oil and Gas Operating Statistics *(Unaudited)*

For the Three Months Ended September 30, 2002

OPERATING STATISTICS

PER-UNIT RESULTS (continued)	2002 Q3	2002 Q2
Conventional Light and Medium Oil *($/bbl)*		
Price, net of transportation and selling	**35.12**	33.76
Royalties	**4.56**	4.36
Operating expenses	**6.58**	7.25
Netback including hedge	**23.98**	22.15
Hedge*	**(0.89)**	(1.59)
Netback excluding hedge	**24.87**	23.74
Conventional Heavy Oil *($/bbl)*		
Price, net of transportation and selling	**28.55**	26.09
Royalties	**3.67**	3.09
Operating expenses	**6.71**	5.87
Netback including hedge	**18.17**	17.13
Hedge*	**(0.89)**	(0.76)
Netback excluding hedge	**19.06**	17.89
Total Conventional Oil *($/bbl)*		
Price, net of transportation and selling	**31.49**	29.67
Royalties	**4.07**	3.68
Operating expenses	**6.66**	6.51
Netback including hedge	**20.76**	19.48
Hedge*	**(0.89)**	(1.15)
Netback excluding hedge	**21.65**	20.63
Natural Gas Liquids *($/bbl)*		
Price, net of transportation and selling	**31.18**	29.92
Royalties	**4.62**	4.69
Netback	**26.56**	25.23
Syncrude *($/bbl)*		
Price, net of transportation and selling	**42.54**	40.09
Gross overriding royalty and other revenue	**0.17**	0.16
Royalties	**0.43**	0.42
Cash operating expenses	**13.38**	30.47
Netback including hedge	**28.90**	9.36
Hedge*	**(1.19)**	(0.42)
Netback excluding hedge	**30.09**	9.78
Ecuador Oil *($/bbl)*		
Price, net of transportation and selling	**33.59**	31.63
Royalties	**12.51**	10.76
Operating expenses	**4.60**	5.70
Netback including hedge	**16.48**	15.17
Hedge*	**–**	(0.04)
Netback excluding hedge	**16.48**	15.21
United Kingdom Oil *($/bbl)*		
Price, net of transportation and selling	**39.30**	37.78
Operating expenses	**5.71**	3.12
Netback including hedge	**33.59**	34.66
Hedge	**–**	–
Netback excluding hedge	**33.59**	34.66

* Relates to share of contract volume of 85,000 bbls/d for January to September 2002.

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